

YEAR 1992

ANNUAL REPORT **RECEIVED**

OF

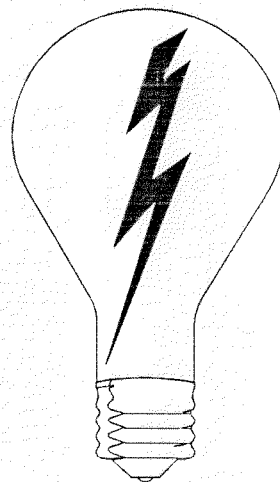
JUN 11 1993

MONT. P. S. COMMISSION

PACIFICORP dba Pacific Power

(COMPANY NAME)

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MONTANA 59620-2601

TABLE OF CONTENTS

<u>Description</u>	<u>Schedule</u>	<u>Page</u>
Instructions		i - v
Identification	1	1
Board of Directors	2	1
Officers	3	2
Corporate Structure	4	3
Corporate Allocations	5	4
Asset Sales, Transfers and Retirements	6	5
Affiliate Transactions - To the Utility	7	6
Affiliate Transactions - By the Utility	8	7
Montana Utility Income Statement	9	8
Montana Revenues	10	8
Montana Operation and Maintenance Expenses	11	9
Montana Taxes Other Than Income	12	13
Payments for Services	13	14
Political Action Committees/Political Contrib.	14	15
Pension Costs	15	16
Other Post Employment Benefits	16	17
Top Ten Montana Compensated Employees	17	19
Balance Sheet	18	20
Montana Plant in Service	19	23
Montana Depreciation Summary	20	26
Montana Materials and Supplies	21	26
Montana Regulatory Capital Structure	22	26

continued on next page

<u>Description</u>	<u>Schedule</u>	<u>Page</u>
Statement of Cash Flows	23	27
Long Term Debt	24	28
Preferred Stock	25	29
Common Stock	26	30
Other Capital	27	31
Montana Earned Rate of Return	28	32
Montana Composite Statistics	29	33
Montana Customer Information	30	34
Montana Employee Counts	31	35
Montana Construction Budget	32	36
Peak and Energy	33	37
Sources and Disposition of Energy	34	37
Sources of Electric Supply	35	38
MT Conservation and Demand Side Mgmt. Programs	36	39

Instructions

General

1. A computer disk, formatted with DOS Version 5.0, is being provided for your convenience. The files were created using the DOS version of Lotus 3.1 and were saved with the wk1 extension. WYSIWYG was used as an addin, these files have the fmt extension. Separate files were created for each page. Where multiple schedules are on one page, one file was created. The naming convention of the files is representative of the schedules contained on a page (for example, Schedules 1 and 2 are sch1&2.wk1, Schedule 3 is sch3.wk1). Use of the disk is optional. The disk shall be returned when the report is filed.
2. All forms shall be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed.
3. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ().
4. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.
5. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).
6. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.
7. All companies owned by another company shall attach a corporate structure chart of the holding company.
8. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

9. The following schedules shall be filled out with information on a total company basis:

Schedules 1 through 5
Schedules 7 and 8
Schedule 15
Schedule 18
Schedules 23 through 27
Schedules 34 and 35

All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

10. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.
11. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 9, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 9A, etc.)

Schedule 6

1. Each sale, transfer or retirement of utility plant with a total combined value (higher of original book cost or selling price) of \$50,000 or more assigned/allocated to Montana shall be reported on this schedule. Each plant item which requires a mortgage release must be reported regardless of its value.

Schedules 7 and 8

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

Schedule 13

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was \$5,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$1,000,000 shall report aggregate payments of \$25,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$10,000,000 shall report aggregate payments of \$75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 15

1. Companies with defined contribution plans do not need to complete lines 25 through 28.
2. Companies with defined benefit plans must complete the entire form. Lines 10 through 23 shall be filled out using FASB 87 guidelines. Line 25 refers to the minimum required contribution under ERISA. Line 27 refers to the maximum amount deductible for tax purposes.

Schedule 16

1. All changes in the employee benefit plans shall be explained in a narrative on lines 16 through 19. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 16 through 19. All assumptions used in quantifying cost containment results shall be disclosed.
2. Lines 36 through 46 on page 1 and lines 18 through 28 on page 2 shall be filled out using FASB 106 guidelines.

Schedule 17

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.
2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)
2. The retention and price/earnings ratios shall be calculated only for the months that earnings and dividends are entered. The price/earnings ratio shall be calculated using the average of the high and low market prices for the given month and the quarterly earnings times 4.
3. Enter the actual year end market price in the "TOTAL Year End" row, this amount shall be used to calculate the year end price/earnings ratio. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 28

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.
2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.
3. Indicate, for each adjustment on lines 28 through 49, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 29

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 32

1. This schedule shall be completed for the year following the reporting year.
2. Respondents shall itemize projects of \$50,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$1,000,000 shall itemize projects of \$100,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$10,000,000 shall itemize projects of \$1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 33

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 35

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Entries for the Other category shall be listed as separate line items and include a description.

Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 36

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.
2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

IDENTIFICATION

Legal Name of Respondent: PacifiCorp

Name Under Which Respondent Does Business: Pacific Power / Utah Power

Date Utility Service First Offered in Montana: May 21, 1954 (Date of Mountain States Power Company merger with Pacific Power)

Person Responsible for Report: Anne E. Eakin - Assistant Vice President

Telephone Number for Report Inquiries: (503) 464-5065

Address for Correspondence Concerning Report:

Pacific Power
1228 Public Service Building
920 S. W. Sixth Avenue
Portland, Oregon 97204

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

BOARD OF DIRECTORS

<u>Director Name & Address (City, State)</u>		<u>Remuneration</u>
1 Don C. Frisbee (Chairman)	Portland, Oregon	\$150,000
2 C. M. Bishop, Jr.	Portland, Oregon	52,442
3 C. Todd Conover	Denver, Colorado	38,735
4 Richard C. Edgley	Salt Lake City, Utah	57,968
5 John C. Hampton	Portland, Oregon	52,442
6 Stanley K. Hathaway	Cheyenne, Wyoming	33,793
7 Michael O. Leavitt	Salt Lake City, Utah	42,947
8 Keith R. McKennon	Midland, Michigan	34,571
9 Don M. Wheeler	Salt Lake City, Utah	49,830
10 Nancy Wilgenbusch	Marylhurst, Oregon	34,542
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		

OFFICERS

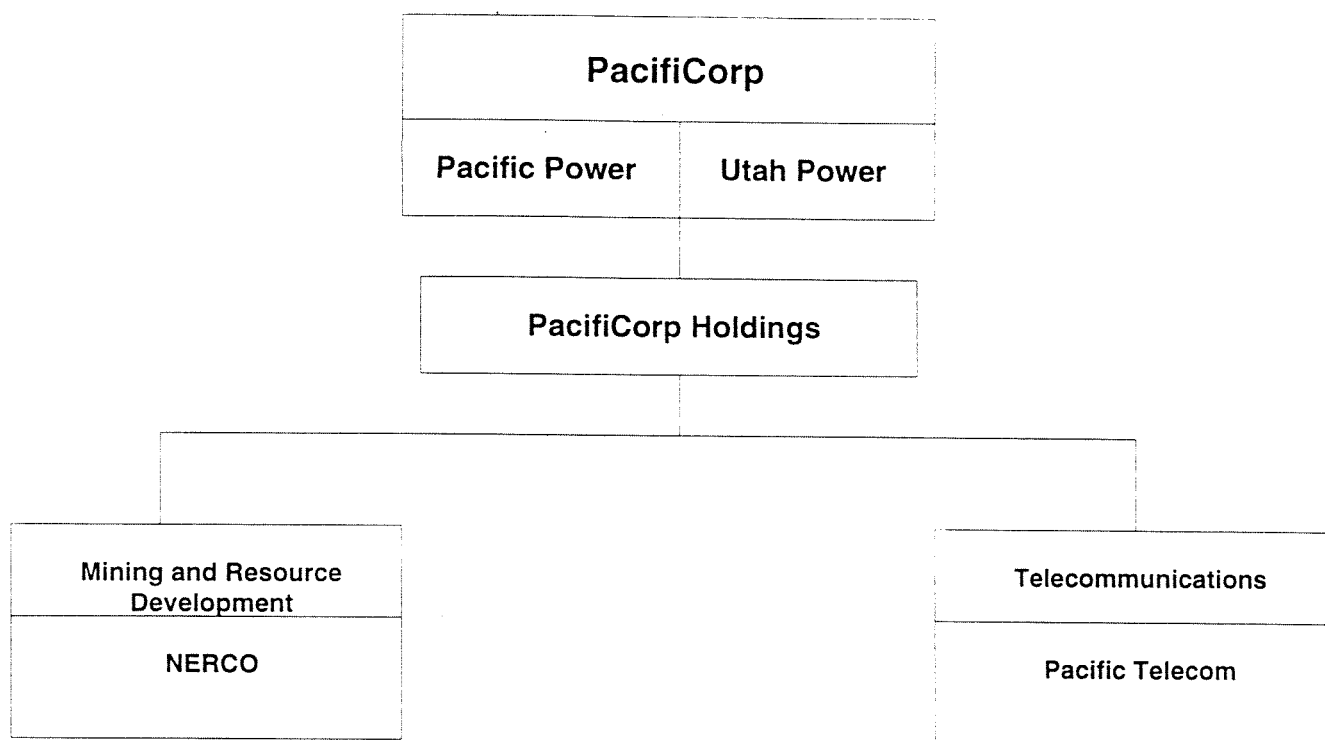
	<u>Title</u>	<u>Department Supervised</u>	<u>Name</u>
1	President and Chief Executive Officer		A. M. Gleason
2			
3	President - Pacific Power		Paul G. Lorenzini
4			
5	President - Utah Power		Verl R. Topham
6			
7	Senior Vice President	Pacific Power Operations	Diana E. Snowden
8			
9	Senior Vice President	Engineering	Harry A. Haycock
10			
11	Senior Vice President	Accounting, Taxes and Financial Planning	Daniel L. Spalding
12			
13			
14	Senior Vice President	Assistant to the President	John A. Bohling
15			
16	Executive Vice President	Utah Power Operations	John E. Mooney
17			
18	Controller		Jacqueline S. Bell
19			
20	Vice President	Thermal Resources	William C. Brauer
21			
22	Vice President	Community & Energy Services, Material Procurement and Division Support	Shelly R. Faigle
23			
24			
25			
26	Vice President	Summit Region	Thomas W. Forsgren
27			
28	Vice President	Public Affairs, Communications and Environmental Policy	Thomas J. Imeson
29			
30			
31	Vice President	Wyoming Region	Thomas A. Lockhart
32			
33	Vice President and Treasurer	Finance	Robert F. Lanz
34			
35	Vice President	Information Management	Stan M. Marks
36			
37	Vice President and Corporate Secretary	Shareholder Services	Sally A. Nofziger
38			
39			
40	Vice President	Human Resources	Michael J. Pittman
41			
42	Vice President	Fuel Resources	Ernest E. Wessman
43			
44	Vice President	Strategic Planning, Mergers/ Acquisitions & Bulk Power Planning	Dennis P. Steinberg
45			
46			
47	Vice President	Rocky Mountain Region	Richard D. Westerberg
48			
49	Assistant Secretary and Controller		H. Arnold Wagner
50			
51			
52			
53			

CORPORATE STRUCTURE

	<u>Subsidiary/Company Name</u>	<u>Line of Business</u>	<u>Earnings</u>	<u>Percent of Total</u>
1	PacifiCorp Holdings, Inc.	Holding company	(587,734,206)	99.98%
2				
3	North American Energy Services Co.	Maintenance of Steam Plants	(212,317)	0.04%
4				
5	Pacific Relocation Service Company	Employee relocations	96,014	-0.02%
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				
53	TOTAL		(587,850,509)	100.00%

THE ORGANIZATION

The Company is a diversified electric utility that conducts its retail electric utility business through two divisions, Pacific Power and Utah Power, and engages in power production and sales on a wholesale basis under the name PacifiCorp. The chart below sets forth the corporate structure of the PacifiCorp Group's three principal businesses:



PacifiCorp Holdings was formed to hold the stock of the Company's principal subsidiaries and to facilitate the conduct of business not regulated as electric utilities. Initially named Inner PacifiCorp, this holding company was renamed PacifiCorp Holdings in 1992. Through PacifiCorp Holdings, the Company indirectly owns:

NERCO (82%), a natural resource company that is a significant producer of coal, gold and silver in North America, and of natural gas and oil in the Gulf Coast region of the United States, and is also engaged in the exploration for and development of precious metals, gas and oil. In 1993, PacifiCorp announced the sale of NERCO. That sale is expected to close mid-1993.

Pacific Telecom (87%), a business providing local telephone service and access to the long distance network in Alaska, seven other western states and three midwestern states, providing intrastate and interstate long distance communication services in Alaska, providing cellular mobile telephone services, and engaging in the sale of capacity in a submarine fiber-optic cable between the U.S. and Japan.

In addition, PacifiCorp Holdings holds PacifiCorp Financial Services (100%), a business offering certain specialized financial services, including aviation financing, computer leasing and real estate investments. PacifiCorp Holdings also has wholly-owned subsidiaries that are engaged in other businesses, including independent power production and co-generation.

The following pages provide an organization chart, in columnar form, of PacifiCorp and its subsidiaries. For each subsidiary, the percentage of ownership held by its parent company is listed as well as the state of incorporation. The listing of subsidiaries also contains a numerical reference for each subsidiary in the organization. This reference number is attached to each affiliated interest entity throughout the report to facilitate cross-referencing.

SUBSIDIARIES OF THE COMPANY

PacifiCorp Holdings, Inc., a wholly-owned subsidiary of the Company and a Delaware corporation, has the following subsidiaries:

	<u>Name of Subsidiary</u>	<u>Approximate Percentage of Voting Securities Owned</u>	<u>State or Jurisdiction of Incorporation or Organization</u>
1	NERCO, Inc.	82%	Oregon
	PACE Group, Inc.	100%	Oregon
2	PacifiCorp Financial Services, Inc.	100%	Oregon
	Pacific Development, Inc.	100%	Oregon
	Pacific Harbor Capital, Inc.	100%	Delaware
	PacifiCorp Capital, Inc.	100%	Virginia
	PacifiCorp Credit, Inc.	100%	Oregon
	Paccomm Leasing Corporation	100%	Oregon
	Vermont Castings, Inc.	100%	Vermont
3	Pacific Generation Company	100%	Oregon
	Energy National, Inc.	100%	Utah
	ONSITE Energy, Inc.	100%	Oregon
4	Pacific Telecom, Inc.	87%	Washington
5	PacifiCorp Trans, Inc.	100%	Oregon

Pacific Telecom, Inc., an 87% owned subsidiary of PacifiCorp Holdings, Inc., and a Washington corporation, has the following subsidiaries:

	<u>Name of Subsidiary</u>	<u>Approximate Percentage of Voting Securities Owned</u>	<u>State or Jurisdiction of Incorporation or Organization</u>
	Alascom, Inc.	100%	Alaska
	Cascade Autovon Company	100%	Washington
	Eagle Telecommunications, Inc./Colorado	100%	Colorado
	Eagle Valley Communications Corporation	100%	Colorado
	Gem State Utilities Corporation	92%	Idaho
	Inter Island Telephone Company, Inc.	100%	Washington
	International Communications Holdings, Inc.	85%	Delaware
	TRT Communications, Inc.	100%	Delaware
	TRT/FTC Communications, Inc.	100%	Delaware
	TRT/FTC International, Inc.	100%	Delaware
	North-West Telecommunications, Inc.	100%	Nevada
	Cencom of Wisconsin, Inc.	100%	Wisconsin
	Northland Telephone Company	100%	Minnesota
	North-West Telephone Company	100%	Wisconsin
	Postville Telephone Company	100%	Wisconsin
	The Footville Telephone Company	100%	Wisconsin
	Sullivan Telephone Company	100%	Wisconsin
	Platteville Telephone Company	100%	Wisconsin
	North-West Cellular, Inc.	100%	Nevada
	Thorp Telephone Company	100%	Wisconsin
	Turtle Lake Telephone Company, Inc.	100%	Wisconsin

Sch. 5 **CORPORATE ALLOCATIONS**

	Items Allocated	Classification	Allocation Method	\$ to MT Utility	MT %	\$ to Other
1	Corporate Management Fee		Three Factor Method			
2	6,429,878.58		61.0% to Electric Operations			
3	Electric Portion					
4	3,922,226.58			64,548	1.6457%	3,857,678
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35	TOTAL			64,548	1.6457%	3,857,678

ASSET SALES, TRANSFERS & RETIREMENTS AFFECTING MT UTILITY

	<u>Plant Description</u>	<u>Plant Account Number</u>	<u>Work Order Number</u>	<u>Item Ever Rate Based (Y or N)</u>	<u>Trans. Date</u>	<u>Trans. Type (S,T,R)</u>	<u>Affiliate Trans. (Y or N)</u>	<u>Mortgage Release (Y or N)</u>	<u>Trans. Amount (000)</u>	<u>Gain Loss (000)</u>
1	Rebuild 12.5 KV Underbuild	364	40903	Y	Jun-92	T	N	N	45	
2	Rebuild 12.5 KV Underbuild	365	40903	Y	Jun-92	T	N	N	25	
3	Rebuild 12.5 KV Underbuild	368	40903	Y	Jun-92	T	N	N	9	
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										

Sch. 7 AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY						
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% Total Affil. Revs	Charges to MT Utility
1	Pacific Telecom	Shareholder Service Records	Cost	159,017	0.02%	2,617
2		Telephone Equipment	Cost	58,571	0.01%	58,571
3		Telephone Svc & Pole Attachments	Cost	83,725	0.01%	3,514
4						
5	NERCO	Fuel Stock	Cost	2,881,802	0.50%	47,198
6						
7	PacifiCorp Financial Services	Leased Office Space	Cost	321,425	0.18%	5,259
8						
9	PacifiCorp Trans, Inc.	Corporate Air Transportation	Cost	4,955,847	67.57%	86,602
10						
11	Pacific Relocation	Moving, Mngmnt & Admin Fees	Cost	163,850	18.35%	2,536
12						
13	Centralia Mining Company	Mine Mngmnt & Mining Svcs	Cost	48,911,133	N/A (1)	801,067
14						
15	Energy West Mining Company	Mine Mngmnt & Mining Svcs	Cost	124,957,860	N/A (1)	2,046,560
16						
17	Glenrock Coal	Fuel Stock	Cost	28,046,619	N/A (1)	459,348
18						
19	Williams Fork Company	Mine Mngmnt & Mining Svcs	Cost	5,387,560	N/A (1)	88,237
20						
21	NESCO	Advanced Engineering Mngmnt & Construction Mngmnt Techniques	Cost	5,063,698	10.39%	139,235
22						
23						
24	Microrim	Software	Cost	618	N/A (2)	10
25						
26						
27						
28						
29	(1) This company is not evaluated on a stand-alone basis. Therefore, no balance sheet or income statement is available.					
30						
31	(2) PacifiCorp owns less than 20% of Microrim and holds its interest as a cost-based investment. Microrim did not provide an annual report.					
32						
33						
34						

Sch. 8 AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Sch. 8		Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% Total Affil. Exp.	Revenues to MT Utility
1		Pacific Telecom	Printing Services	Cost	9,009	0.0016%	0
2			Pole Contact Rental	Cost	120,873	0.0214%	0
3							
4		NERCO	Printing Services	Cost	7,424	0.0008%	0
5			Consulting Services	Cost	8,282	0.0009%	0
6							
7		PacifiCorp Financial Services	Printing Services	Cost	1,002	0.0003%	0
8							
9		Pacific Generation	Printing Services	Cost	938	0.0054%	0
10			Consulting Services	Cost	3,559	0.0206%	0
11							
12		PacifiCorp Trans, Inc.	Printing Services	Cost	1,344	0.0200%	0
13			Accounting & Accts Payable Svcs	Cost	18,000	0.2674%	0
14			Office Rent	Cost	2,846	0.0423%	0
15							
16		Pacific Relocation	Printing Services	Cost	915	0.1231%	0
17			Payroll Processing	Cost	450	0.0606%	0
18			Furniture Rental	Cost	263	0.0354%	0
19							
20							
21							
22							
23							
24							
25	NOTE: Transactions involving services provided by PacifiCorp to affiliated companies are charged to work orders using account 186, Miscellaneous Deferred Debits - Other Work in Progress. On a monthly basis, the balances in each work order are analyzed and cleared to receivable account 146. The affiliate is then billed for the amount due. When payment is received from the affiliate, the receivable is extinguished. Thus, billings to affiliates do not result in charges to accounts affecting ratepayers.						
26							
27							
28							
29							
30							
31							
32							
33							
34							

Sch. 9 MONTANA UTILITY INCOME STATEMENT				
	<u>Account Number & Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
1	400 Operating Revenues	37,690,802	38,472,022	2.07%
2				
3	<u>Operating Expenses</u>			
4	401 Operation Expenses	17,230,564	19,911,551	15.56%
5	402 Maintenance Expenses	2,445,769	2,471,711	1.06%
6	403 Depreciation Expenses	3,666,839	3,994,694	8.94%
7	404-405 Amortization of Electric Plant	148,148	161,730	9.17%
8	406 Amort. of Plant Acquisition Adjustments	9,049	72,765	704.12%
9	407 Amort. of Property Losses, Unrecovered Plant	1,878	0	-100.00%
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	1,234,572	1,386,989	12.35%
12	409.1 Income Taxes - Federal	2,396,425	1,649,811	-31.16%
13	- Other	565,050	359,033	-36.46%
14	410.1 Provision for Deferred Income Taxes	351,335	1,494,970	325.51%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(267,538)	(605,403)	126.29%
16	411.4 Investment Tax Credit Adjustment	0	0	
17	411.6 (Less) Gains from Disposition of Utility Plant	0		
18	411.7 Losses from Disposition of Utility Plant	0		
19				
20	TOTAL Utility Operating Expenses	27,782,091	30,897,852	11.21%
21				
22	NET UTILITY OPERATING INCOME	9,908,711	7,574,170	-23.56%

Sch. 10 MONTANA REVENUES				
	<u>Account Number & Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
1	<u>Sales of Electricity</u>			
2	440 Residential	13,926,844	14,041,531	0.82%
3	442 Commercial & Industrial - Small	9,821,250	10,179,308	3.65%
4	Commercial & Industrial - Large	8,027,993	7,148,965	-10.95%
5	444 Public Street & Highway Lighting	136,118	138,225	1.55%
6	445 Other Sales to Public Authorities	0	0	
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales	28,328	(10)	-100.04%
9				
10	TOTAL Sales to Ultimate Consumers	31,940,533	31,508,019	-1.35%
11	447 Sales for Resale	5,314,706	6,754,597	27.09%
12				
13	TOTAL Sales of Electricity	37,255,239	38,262,616	2.70%
14	449.1 (Less) Provision for Rate Refunds	0	(45,662)	
15				
16	TOTAL Revenue Net of Provision for Refunds	37,255,239	38,216,953	2.58%
17	<u>Other Operating Revenues</u>			
18	450 Forfeited Discounts & Late Payment Revenues	16,467	15,663	-4.88%
19	451 Miscellaneous Service Revenues	9,281	3,530	-61.96%
20	453 Sales of Water & Water Power	2,231	2,277	2.05%
21	454 Rent From Electric Property	137,197	184,369	34.38%
22	455 Interdepartmental Rents		0	
23	456 Other Electric Revenues	270,387	49,230	-81.79%
24				
25	TOTAL Other Operating Revenues	435,563	255,069	-41.44%
26				
27	Total Electric Operating Revenues	37,690,802	38,472,022	2.07%

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits

during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is a diversified utility that conducts its retail electric utility business through two divisions, Pacific Power & Light Company ("Pacific Power") and Utah Power & Light Company ("Utah Power"), and engages in power production and sales on a wholesale basis under the name PacifiCorp. The Company holds investments through its wholly-owned subsidiary PacifiCorp Holdings, Inc. ("Holdings," formerly Inner PacifiCorp, Inc.), in subsidiaries including a telecommunications company (Pacific Telecom, Inc.) and a financial services company (PacifiCorp Financial Services, Inc.)

The Company also holds investments in a mining and resources development business (NERCO, Inc.) and an international communications business (International Communications Holdings, Inc.) through Holdings. The Company has agreed to the disposal of these operations. See Note 12.

These regulatory basis financial statements have been prepared for the purpose of complying with, and on the basis of accounting practices specified by the Federal Energy Regulatory Commission ("FERC"). Accordingly, investments in subsidiaries are accounted for and reported on the equity basis of accounting and these regulatory basis financial statements do not include debt of the Leveraged ESOP Trust established under the PacifiCorp K Plus Employee Savings and Stock Ownership Plan ("K Plus Plan") which is guaranteed by Holdings and do not present financial position, results of operations and changes in cash flows in accordance with generally accepted accounting principles, which would require that the accounts of the subsidiaries be consolidated with those of PacifiCorp.

The Company and Holdings guarantee certain debt of the Leveraged ESOP Trust established under the K Plus Plan ("the Trust"). The amounts guaranteed at December 31, 1992 were \$27,286,000 and \$30,098,000 for the Company and Holdings, respectively. In addition, the Company and Holdings guarantee the Trust's performance under certain interest rate swaps having a total notional principal amount of \$48,000,000 that were entered into by the Trust and a commercial bank. These arrangements change the interest rate exposure on the variable rate debt guaranteed by the Company to effective rates of 6.9 percent and 7 percent, respectively, at December 31, 1992. The debt was used to acquire the Company's common stock. Remaining unallocated common shares total 2,614,252.

If generally accepted accounting principles were followed, current assets (in thousands of dollars) would have been increased by \$299,883 and \$304,210; property, plant and equipment would have been increased by \$1,078,899 and \$1,168,469; current liabilities would have been increased by \$508,966 and \$371,634; long-term debt would have been increased by \$818,002 and \$1,107,551; deferred credits would have been increased by \$667,533 and \$823,627; Financial Services' investments would have been \$1,114,308 and \$1,461,552 and Financial Services' debt would have been \$715,640 and \$1,014,013 as of December 31, 1992 and 1991, respectively. Furthermore, operating revenues would have been increased by \$879,589 and \$916,563; operating expenses would have been increased by \$753,255 and \$577,522 for the years ended December 31, 1992 and 1991, respectively. Net cash provided by operating activities would have been increased by \$342,280 and net cash used by investing activities would have been decreased by \$144,976, for the year ended December 31, 1992. The accounting for investments in subsidiaries on the equity method rather than in accordance with generally accepted accounting principles has no effect on net income; however, on a consolidated basis, common shareholder capital would have been decreased by \$21,156 and \$28,122 and retained earnings would have been increased by \$9,643 and \$8,953 as of December 31, 1992 and 1991, respectively, due to Holding's purchase of common stock of the Company and subsequent dividend declarations (see Note 4).

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Regulatory Authorities

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by the FERC and the regulatory commissions of the various states in which the Company operates.

Cash and Cash Equivalents

For the purposes of these financial statements, the Company considers all liquid investments with original maturities of three months or less to be cash equivalents.

Electric Property, Plant and Equipment

Electric property, plant and equipment are stated at original cost of contracted services, direct labor and material, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation. Maintenance and repairs of property and replacement and renewals of items that are not units of property are charged to operating expense.

Depreciation and Amortization

Depreciation and amortization is computed generally by the straight-line method over the estimated useful lives of the related assets. Provision for depreciation of electric plant (excluding amortization of capital leases) was 3.2 percent of average depreciable assets in 1992 and 1991.

Inventory Valuation

Inventories are generally valued at the lower of average cost or market.

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rate allowed was 7.1 percent in 1992 and 9.3 percent in 1991.

Income Taxes

The Company provides deferred taxes for differences due to book versus tax depreciation lives and methods and certain other timing differences. Pursuant to regulatory orders, deferred income taxes are not provided for certain other differences. It is expected that regulatory practices affecting the utility business will permit recovery through revenues of income taxes, not provided for currently, when such taxes become payable.

Investment tax credits are deferred and amortized to income over the average estimated lives of the properties in accordance with the accounting practices prescribed by regulatory authorities.

Revenue Recognition

The Company accrues estimated unbilled revenues for services provided after cycle billing through month-end.

NOTE 2. ACQUISITIONS

On April 15, 1992, the Company purchased 243 megawatts of generating assets and fuel resources from Colorado-Ute Electric Association, Inc. for \$279,264,000. The purchase was financed with \$250,338,000 of First Mortgage and Collateral Trust Bonds ("FMB"), including \$47,540,000 of FMB issued as collateral for obligations assumed relating to pollution control revenue bonds.

On April 8, 1991, the Company purchased equity interests in the Wyodak Plant. On June 8, 1991, the Company retired its share of the Wyodak debt, which had been recorded as a capital lease obligation, with issuances of medium-term notes and cash.

Name of Respondent PacifiCorp	This Report is: (1) [X] An Original (2) [] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	--	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Noncash investing and financing activities associated with these acquisitions were as follows:

	MILLIONS OF DOLLARS	
	1992	1991
Net assets acquired	\$(279,264)	\$(169,916)
Disposition of net property under capital lease	-	132,471
Long-term debt assumed	250,338	105,646
Accrued liabilities and deferred credits assumed	4,845	7,968
Retirement of obligations under capital lease	-	(132,471)

On July 15, 1991, the Company paid \$234 million to Arizona Public Service Company ("APS") for Unit No. 4 of the Cholla coal-fired generating plant and related common facilities and commenced providing power to APS under a related power supply agreement.

NOTE 3. SHORT-TERM BORROWING ARRANGEMENTS

At December 31, 1992, the Company had outstanding \$232,422,634 in commercial paper and \$130,200,000 of borrowings under available bank lines backed by a \$500 million revolving credit agreement. The Company has the intent and ability to support short-term borrowings through various revolving credit agreements on a long-term basis. Commitment fees were \$619,177 and \$443,576 in 1992 and 1991, respectively. Covenants in certain reimbursement agreements relating to letters of credit limit short-term borrowings to 12% of defined capitalization (limiting such borrowings to approximately \$360,500,000 at December 31, 1992).

NOTE 4. COMMON AND PREFERRED STOCK

At December 31, 1992 and 1991, the Company had authorized common stock of 750,000,000 shares. The Company had 270,579,042 and 262,411,351 outstanding common shares at December 31, 1992 and 1991, respectively.

Changes in shares of capital stock and common shareholder capital are listed below:

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHAREHOLDER CAPITAL
BALANCE, JANUARY 1, 1991	253,204	3,843	\$2,405,871
1991 Sales through Dividend Reinvestment and Stock Purchase Plan	2,933	-	65,157
Sales through Employees' Stock Plans	224	-	5,191
Sales to the public	6,050	1,000	130,513
Stock expense, redemptions and repurchases			(4,812)
BALANCE, DECEMBER 31, 1991	262,411	4,843	2,601,920
1992 Sales through Dividend Reinvestment and Stock Purchase Plan	3,790	-	81,551
Sales through Employees' Stock Plans	1,070	-	23,395
Sales to the public	3,308	5,750	74,661
Stock expense, redemptions and repurchases		(60)	(5,433)
BALANCE, DECEMBER 31, 1992	<u>270,579</u>	<u>10,533</u>	<u>\$2,776,094</u>

Holdings held 314,982 of the outstanding shares included in the table above at December 31, 1991. Holdings sold all of its PacifiCorp shares in 1992 to the Leveraged ESOP Trust established under the K Plus Plan and to the Company for use as awards in the PacifiCorp Long-Term Incentive Plan.

At December 31, 1992, there were 14,478,255 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan, the K Plus Plan and for sales to the public. Eligible employees under the K Plus Plan may direct their pretax elective contributions into the purchase of the Company's common stock. The Company makes matching contributions equal to a percentage of employee contributions which are also invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6% of compensation.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends.

THOUSANDS OF SHARES/DOLLARS

PREFERRED STOCK OUTSTANDING AT DECEMBER 31

SERIES	1992 SHARES	1992 AMOUNT	1991 SHARES	1991 AMOUNT
SUBJECT TO MANDATORY REDEMPTION:				
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
\$7.12 (\$100 stated value)	440	\$ 44,000	500	\$ 50,000
7.48	750	75,000	-	-
7.70	1,000	100,000	1,000	100,000
TOTAL SUBJECT TO MANDATORY REDEMPTION		<u>\$219,000</u>		<u>\$150,000</u>
NOT SUBJECT TO MANDATORY REDEMPTION:				
SERIAL PREFERRED \$100 STATED VALUE PER SHARE, 3,500 SHARES AUTHORIZED				
4.52%	2	\$ 207	2	\$ 207
4.56%	85	8,459	85	8,459
4.72%	70	6,989	70	6,989
5.00%	42	4,200	42	4,200
5.40%	66	6,596	66	6,596
6.00%	6	593	6	593
7.00%	18	1,806	18	1,806
7.96%	135	13,518	135	13,518
8.92%	69	6,937	69	6,937
9.08%	165	16,489	165	16,489
NO PAR SERIAL PREFERRED, 16,000 SHARES AUTHORIZED				
\$1.16 (\$25 stated value)	193	4,828	193	4,828
\$1.18	420	10,503	420	10,503
\$1.28	381	9,530	381	9,530
\$1.76	394	9,847	394	9,847
\$1.98	502	12,550	502	12,550
\$1.98, Series 1992	5,000	125,000	-	-
\$2.13	666	16,655	666	16,655
Auction Rate (\$100,000 stated value) (a)	2	150,000	2	200,000
5% PREFERRED, \$100 STATED VALUE, 127 SHARES AUTHORIZED AND OUTSTANDING	127	12,653	127	12,653
TOTAL NOT SUBJECT TO MANDATORY REDEMPTION		<u>\$417,360</u>		<u>\$342,360</u>

(a) Dividend rates at December 31, 1992 on 500 shares of Series A, Series B and Series C were 4.1%, 4.3%, and 4.5%, respectively.

The estimated fair value, based upon bid prices from an investment bank, of the redeemable preferred stock would be approximately 1 percent less than its carrying value of \$219,000,000 at December 31, 1992.

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: beginning in 1997, 15,000 shares of the \$7.12 series are redeemable annually; the \$7.70 series is redeemable in its entirety on August 15, 2001; and 37,500 shares of the \$7.48 series are redeemable on each June 15 from 2002 through 2006, with shares outstanding on June 15, 2007 redeemable on that date. Mandatory redemption requirements for 1993 through 1996 on the \$7.12 series were satisfied by the purchase of 60,000 shares at a discount in December 1992. If the Company is in default in its obligation to make any future redemptions on the \$7.12 series or the \$7.48 series, it may not pay cash dividends on common stock.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

On January 25, 1993, the Company redeemed its \$50 million of Series B Auction Rate Preferred Stock.

NOTE 5. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

The Company's long-term debt and capital lease obligations were as follows:

THOUSANDS OF DOLLARS/DECEMBER 31,	1992	1991
FIRST MORTGAGE AND COLLATERAL TRUST BONDS		
Maturing 1993 through 1997 / 4.5% - 9.4% (a)	\$ 370,287	\$ 490,415
Maturing 1998 through 2002 / 6.5% - 10%	879,451	599,251
Maturing 2003 through 2007 / 7% - 9%	520,788	441,516
Maturing 2008 through 2012 / 8% - 9.2%	152,783	76,000
Maturing 2013 through 2017 / 8.3% - 8.8%	218,519	357,000
Maturing 2018 through 2022 / 8.1% - 8.5%	175,000	20,000
Redeemed in February 1992	-	201,306
GUARANTY OF POLLUTION CONTROL REVENUE BONDS		
6% due 2003	21,260	36,900
5.9% - 10.7% due 1993 through 2017 (b)	272,880	249,640
Variable rate due 2005 through 2019 (c)	407,425	369,300
Funds held by trustees	(885)	(852)
OTHER		
Unamortized premium and (discount)	10,984	11,014
Capital lease obligations (Note 6)	18,247	20,033
TOTAL	3,046,739	2,871,523
Less current maturities	52,294	68,049
LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS	<u>\$2,994,445</u>	<u>\$2,803,474</u>

(a) Includes \$50,000 in 9 3/8% bonds issued to secure obligations under an equivalent 10-year yen loan. A currency swap converted the fixed rate yen liability to a floating rate U.S. dollar liability based on six-month LIBOR plus 0.02% (interest rate 3.6% at December 31, 1992).

(b) Secured by pledged first mortgage bonds and collateral trust generally at the same interest rates, maturity dates and redemption provisions as the secured pollution control revenue bonds.

(c) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates or prime rates.

In accordance with Statement of Financial Accounting Standards ("FAS") 107, "Disclosures about Fair Value of Financial Instruments," the fair value of the Company's long-term debt at December 31, 1992, has been estimated by discounting the projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. The fair value of the Company's total long-term debt at December 31, 1992 would be approximately 3% more than its carrying value of \$2,994,445.

The Company has entered into interest rate swap and exchange agreements to reduce the impact of changes in interest rates on its variable rate long-term debt. At December 31, 1992, the Company had five outstanding interest rate contracts with commercial banks and Fortune 500 service companies, having a total notional principal amount of \$187,000,000. These agreements change the Company's interest rate exposure on the underlying variable rate debt to fixed rates of 6.9% to 8.9%. These contracts mature at various times up to the year 2000. The Company is exposed to credit loss in the event of nonperformance by the other parties to the interest rate swap agreements. However, the Company does not anticipate nonperformance by the counterparties.

The fair value of interest rate swaps is the estimated amount that the Company would pay to terminate the swap agreements, taking into account current interest rates and the credit worthiness of the swap counterparties. The estimated termination cost would have been (in thousands) \$55,895 at December 31, 1992.

Approximately \$4.3 billion of the assets of the Company secure long-term debt and capital lease obligations. First mortgage and collateral trust bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Maturity and sinking fund requirements on all long-term debt, long-term capital lease obligations and redeemable preferred stock outstanding are as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1993	1994	1995	1996	1997
Total requirements	\$54,069	\$70,598	\$48,619	\$151,741	\$212,974
Portion of total payable in cash	52,294	69,036	47,469	150,591	210,374
Property additions certifiable in lieu of cash (a)	3,063	2,375	1,438	750	750

(a) Certain cash sinking fund requirements may be satisfied on the basis generally of 60% of property additions.

The Company's Mortgage and Deeds of Trust, as supplemented, relating to its long-term debt, restrict the payment of cash dividends and other distributions on common stock. At December 31, 1992, the Company's retained earnings available for these purposes were \$125 million.

The Company made interest payments, net of capitalized interest, of \$256.7 million and \$250.8 million in 1992 and 1991, respectively.

NOTE 6. LEASES

The Company leases certain properties under leases expiring during the next 29 years. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property. Capital leases currently in effect are not significant.

Net rent expense, including amounts attributable to capitalized leases, for the years ending December 31, 1992 and 1991 was (in thousands) \$14,890 and \$18,563, respectively.

Future minimum lease payments under noncancelable operating leases are (in thousands) \$4,979, \$4,020, \$2,803, \$721 and \$721 for 1993 through 1997, respectively.

NOTE 7. COMMITMENTS AND CONTINGENCIES

Construction and Other

Construction programs are estimated at \$793 million for 1993. As part of these programs, substantial commitments have been made.

Several Superfund sites have been identified where the Company has been or may be designated as potentially a responsible party. Future costs associated with the disposition of these matters are not expected to be material to the Company's financial position and results of operations.

The Company is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management presently believes that disposition of these matters will not have a materially adverse effect on the Company's financial position and results of operations.

Name of Respondent PacifiCorp	This Report is: (1) [X] An Original (2) [] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	--	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Jointly Owned and Leased Plant

At December 31, 1992, the Company's participation in plants jointly owned and jointly leased was as follows:

THOUSANDS OF DOLLARS	The Company's Share	Plant in Service	Accumulated Depreciation	Work in Progress
JOINTLY OWNED PLANTS				
Centralia	47.5%	\$173,516	\$ 94,906	\$ 265
Jim Bridger Units 1, 2, 3 and 4	66.7%	773,521	261,948	6,473
Trojan (a)	2.5%	-	-	-
Colstrip Units 3 and 4	10.0%	198,888	42,465	554
Hunter Unit 1	93.8%	252,237	81,159	129
Hunter Unit 2	60.3%	179,327	53,404	218
Wyodak	80.0%	287,798	80,366	5,849
Craig Station, Units 1 and 2	19.3%	143,993 (b)	43,804	1,478
Hayden Station, Unit 1	24.5%	15,134 (b)	10,789	290
Hayden Station, Unit 2	12.6%	16,426 (b)	7,576	175

(a) Plant in service, accumulated depreciation, and construction work in progress balances of \$20,580, \$8,675, and \$1,779, respectively, relating to the Trojan Plant, along with estimated plant closure and decommissioning costs of \$15,237 and fuel inventory costs of \$1,976 were included in Unrecovered Plant and Regulatory Study Costs. Recovery of these costs is pending approval of certain regulatory commissions.

(b) Excludes unallocated acquisition adjustments of \$142,000.

Under the joint agreements, each participating utility is responsible for financing its share of construction operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts.

Substantial amounts of power are purchased from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expense and debt service). These costs are included in operations expense. The Company is required to pay its portion of the debt service, whether or not any power is produced. The arrangements provide for nonwithdrawable power and most of them also provide for additional power, withdrawable by the districts upon one to five years notice. For 1992, such purchases approximated 3.3 percent of energy requirements; an additional 9.9 percent was obtained through other purchase and net interchange arrangements.

A summary of the Company's share of long-term arrangements with public utility districts at December 31, 1992, was as follows:

Generating Facility	Year Contract Expires	Capacity (kw)	Percentage of Output	Annual Costs (a) (in thousands)
Wanapum	2009	155,444	18.7%	\$ 4,430
Priest Rapids	2005	109,602	13.9	3,141
Rocky Reach	2011	64,297	5.3	1,740
Wells	2018	54,198	7.0	1,642
TOTAL		<u>383,541</u>		<u>\$10,953</u>

(a) Annual costs include debt service of \$6,151.

The Company has a 4 percent interest in the Intermountain Power Project ("Project"), located in central Utah. The Company and the City of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4 percent entitlement of the Project at a price equivalent to 4 percent of the expenses and debt service of the Project.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 8. INCOME TAXES

Excluding the equity in earnings of subsidiaries companies, the Company's effective combined Federal and state income tax rate was 39 percent and 32 percent in 1992 and 1991. The difference between taxes calculated as if the statutory Federal tax rate of 34 percent was applied to income before income taxes, and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS/FOR THE YEAR	1992	1991
COMPUTED FEDERAL INCOME TAXES	<u>\$137,566</u>	<u>\$185,575</u>
REDUCTION IN TAX RESULTING FROM		
Excess of tax over book depreciation (flow-through basis)	(20,329)	1,849
Investment tax credit	9,440	9,952
Depletion	4,944	5,177
Other items capitalized and miscellaneous differences	<u>(2,218)</u>	<u>5,148</u>
Federal tax reductions	<u>(8,163)</u>	<u>22,126</u>
FEDERAL INCOME TAX	145,729	163,449
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	<u>11,953</u>	<u>10,823</u>
TOTAL INCOME TAX EXPENSE	<u>\$157,682</u>	<u>\$174,272</u>
INCOME TAX EXPENSE CONSISTS OF THE FOLLOWING		
TAXES CURRENTLY PROVIDED		
Federal	\$101,179	\$178,771
State	12,370	24,120
DEFERRED INCOME TAXES		
Depreciation differences	48,984	27,214
Sale of contract entitlements	-	(42,862)
Loss on post-merger reacquired debt	12,170	-
Other	(7,552)	(2,993)
INVESTMENT TAX CREDITS/NET	<u>(9,469)</u>	<u>(9,978)</u>
TOTAL INCOME TAX EXPENSE	<u>\$157,682</u>	<u>\$174,272</u>

Income taxes are not provided on the Company's share of income or losses relating to those investments for which it uses the equity method of accounting.

During 1990, the Internal Revenue Service ("IRS") completed its examination of the Company's federal income tax returns for the years 1983 through 1986, and has proposed certain adjustments that could substantially increase the tax for these years. The Company and the IRS have agreed to a partial settlement on many of the issues. Among the remaining unagreed issues, the IRS is challenging the Company's abandonment of its 10 percent interest in Washington Public Power Supply System Unit 3. The remaining unagreed issues represent the IRS's initial audit position on specific issues and the IRS has not issued a formal notice of tax deficiency. The Company and the IRS continue to discuss the remaining unagreed issues, which await two technical advice memoranda from the national office of the IRS. In the opinion of management, based in part on discussions with counsel, the outcome will not have a material effect on the Company's consolidated financial position or results of operations.

Deferred income taxes have not been provided on certain book and tax timing differences as the method of rate-making is based on taxes currently payable, and it is expected that there will be recovery of future taxes through revenues. At December 31, 1992, accumulated timing differences for which deferred taxes have not been provided amounted to approximately (in thousands) \$1,246,000.

The Company adopted the Statement of FAS 109, "Accounting for Income Taxes," effective January 1, 1993. The statement requires that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at rates that are expected to be in effect when the temporary differences reverse. As a result of the adoption of FAS 109, 1993 net income will be increased by approximately (in thousands) \$2,100, assets will be increased by approximately \$780,000 and liabilities will be increased by approximately \$780,000. This adjustment includes deferred income tax liabilities and related regulatory assets recorded for cumulative income tax temporary differences which will be recovered through rates when the temporary differences reverse.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

The Company made income tax payments, net of refunds of (in thousands) \$167,457 and \$183,641 in 1992 and 1991, respectively.

NOTE 9. RETIREMENT PLANS

The Company has pension plans covering substantially all of its employees. Benefits under these plans are generally based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments, to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. Unfunded prior service costs are amortized over the remaining service period of employees expected to receive benefits. At December 31, 1992, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

Net pension costs are summarized as follows for the years ended December 31, 1992 and 1991:

THOUSANDS OF DOLLARS	1992	1991
Service cost - benefits earned	\$ 12,466	\$ 11,673
Interest cost on projected benefit obligation	57,141	55,284
Actual gain on plan assets	(16,824)	(81,363)
Net amortization and deferral	(18,689)	48,561
Regulatory deferral (a)	(6,486)	(33,128)
NET PENSION COST	<u>\$ 27,608</u>	<u>\$ 1,027</u>

(a) The Company has received accounting orders from its primary and certain other regulatory authorities to defer the difference between pension cost as determined in accordance with FAS 87 and 88 and that determined for funding purposes.

The funded status, net pension liability and significant assumptions are as follows at December 31, 1992 and 1991:

THOUSANDS OF DOLLARS	PLAN WITH ACCUMULATED BENEFITS IN EXCESS OF ASSETS		PLAN WITH ASSETS IN EXCESS OF ACCUMULATED BENEFITS
	1992	1991	1991
Actuarial present value of benefit obligations:			
Vested benefit obligation	\$ 550,362	\$ 537,822	\$ 20,367
Accumulated benefit obligation	612,264	576,296	21,853
Projected benefit obligation	689,863	631,428	25,745
Plan assets at fair value	461,069	444,992	33,244
Assets in excess of (or less than)			
projected benefit obligation	(228,794)	(186,436)	7,499
Unrecognized prior service costs	9,911	10,833	-
Unrecognized net (gain) loss	(77,288)	(107,098)	(2,474)
Unrecognized net obligation at January 1, being amortized over 7 to 22 years	115,044	122,107	-
Minimum liability adjustment	(26,778)	(57,519)	-
NET PENSION ASSET (LIABILITY)	<u>\$(207,905)</u>	<u>\$(218,113)</u>	<u>\$ 5,025</u>
Discount rate	9%	9%	8.5%
Expected long-term rate of return on assets on assets	9%	9%	9%
Rate of increase in compensation levels levels	6%	6%	5%

Name of Respondent PacifiCorp	This Report is: (1) [X] An Original (2) [] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	--	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

During 1990, as part of its overall cost reduction program, the Company offered an early retirement incentive program. Included in the table above is the present value of all future termination benefits provided of \$47,188,000. The Company has received regulatory accounting orders to defer these costs as a regulatory asset to be amortized over thirty years.

The Company provides health care and life insurance benefits for its retirees on a basis substantially similar to those who are active employees. The cost of these benefits, which is charged to expense as incurred, was (in thousands) \$9,959 in 1992 and \$8,733 in 1991.

The Company adopted FAS 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions," effective January 1, 1993. This statement requires accrual of postretirement benefits, such as health care benefits, during the years an employee provides services. Based upon the most recent actuarial studies, it is estimated the Company has a transition obligation liability of (in thousands) \$247,400. The 1993 expense will increase by approximately \$20,300, including interest cost, service cost and amortization of the transition obligation. These expenses are not currently included in electric rates. During 1992, action was undertaken in a majority of the Company's regulatory jurisdictions to determine treatment of FAS 106 costs for rate recovery. All but one jurisdiction allowed total FAS 106 costs in principle. Of these jurisdictions, one allowed deferral of the incremental costs until the next general rate case in that jurisdiction and provided assurance of future recovery of deferred amounts. Only one jurisdiction, Utah, which regulates approximately 30 percent of the Company's retail sales, adopted a level of allowed costs less than total FAS 106 costs. A rehearing of that commission's order has been held and the ultimate outcome of the proceeding is still pending. Final decisions as to recovery of these costs will be made during a general rate case. The Company does not plan to file a general rate case in 1993.

NOTE 10. RELATED PARTY TRANSACTIONS

The Company and its subsidiaries participate in a consolidated cash management program. Any funds advanced to/from the Company are included in notes receivable/payable-affiliates. These notes are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements between the Company and its subsidiaries. Net interest expense (income) on these advances was (in thousands) \$195 and \$(1,957) in 1992 and 1991, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were (in thousands) \$2,508 and \$5,071 in 1992 and 1991, respectively.

During 1990 and 1989, Holdings purchased shares of the Company's common stock which were used in acquisitions of companies providing communications services in the Midwest by Pacific Telecom, Inc. ("PTI"). PTI provided the funding for the purchase of these shares. The shares not used in the acquisitions were sold to Holdings in 1992, to the K Plus Plan Trust and to the Company for use as awards in the PacifiCorp Long-Term Incentive Plan. Dividends paid to Holdings on these shares were (in thousands) \$150 and \$488 in 1992 and 1991, respectively.

All of the coal production of the Bridger mine is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were (in thousands) \$124,700 in 1992 and \$118,500 in 1991. In addition, Bridger paid overriding royalties of \$639 and \$604 to the Company and Idaho in 1992 and 1991, respectively, pursuant to coal lease agreements.

NOTE 11. SUBSIDIARY SPECIAL CHARGES

As a result of credit rating downgrades, Financial Services and Holdings have been experiencing restricted access to debt markets. In order to improve this situation, these subsidiaries have attempted to reduce debt with cash generated by accelerating disinvestment of underperforming and nonstrategic assets. In addition, the Company announced, as a part of its strategic direction, its intent to reduce Financial Services' assets to less than 10 percent of the Company's consolidated assets, which were (in thousands) \$11,256,500 at December 31, 1992. The disposition process was being accelerated into an unsettled market for certain of these investments. Related to these actions, Financial Services and Holdings recorded various pretax adjustments of (in thousands) \$141,755 and \$43,940, respectively, to the carrying value of certain of their assets in the first quarter of 1992.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

A summary of the special charges included in equity in subsidiary (earnings) losses is as follows:

Holdings	\$ 29,000
Financial Services	102,583
TOTAL	<u>\$131,583</u>

NOTE 12. DISCONTINUED OPERATIONS OF SUBSIDIARIES

On February 18, 1993, Holdings announced an agreement to sell, by means of a merger, its 82 percent-owned mining and resource development business, NERCO, Inc. ("NERCO"), to Kennecott Corporation ("Kennecott") for cash consideration of \$12 per NERCO share, or \$384 million, subject to adjustment in certain events. In connection with the proposed merger transaction, a subsidiary of Holdings will, if requested, lend \$225 million to a subsidiary of Kennecott. The loan is to be repaid as, and only to the extent that, the borrower receives certain future contract revenues. The merger, which is subject to NERCO shareholder approval, is expected to be completed in the second quarter of 1993 and would result in a pretax gain to Holdings of approximately \$154 million. The gain will be recognized over the life of the loan, which could extend through 2009. Holdings has agreed to vote its NERCO shares in favor of the merger.

The net assets attributable to NERCO included in the carrying value of Holdings are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31	
	1992	1991
Current assets	\$ 151,100	\$ 198,500
Noncurrent assets	1,075,047	1,822,025
Notes payable	(381,700)	(13,900)
Current portion of long-term debt and capital lease obligations	(309,900)	(52,800)
Other current liabilities	(161,500)	(182,300)
Long-term debt	-	(660,100)
Noncurrent liabilities	(96,300)	(248,700)
Minority interest	(50,399)	(154,494)
NET ASSETS OF DISCONTINUED OPERATIONS	<u>\$ 226,348</u>	<u>\$ 708,231</u>

The discontinued operations of NERCO are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31	
	1992	1991
Revenues	\$ 671,998	\$ 919,582
Costs and expenses	668,071	803,688
Losses on asset dispositions and write-downs	710,800	-
Income (loss) from operations before income taxes	(706,873)	115,894
Income tax (benefit) expense	(155,648)	32,761
Minority interest and other	100,318	(15,414)
INCOME (LOSS) FROM DISCONTINUED OPERATIONS	<u>\$ (450,907)</u>	<u>\$ 67,719</u>

A subsidiary of Pacific Telecom, Inc. ("Pacific Telecom") has been shown as a discontinued operation pending completion of an agreement of sale, expected to close in the third quarter of 1993.

Holdings incurred after-tax losses attributable to Pacific Telecom's discontinued operations totaling (in thousands) \$39,703 in 1992, \$9,052 of operating losses and \$30,651 of valuation adjustments, and \$7,318 in 1991. The net assets of these discontinued operations included in the carrying value of Holdings were \$86,102 and \$133,059 at December 31, 1992 and 1991, respectively.

NERCO would have been in default of certain loan covenants as a result of losses incurred in 1992 if it had not obtained waivers for the period ended December 31, 1992. NERCO has also obtained waivers of these covenants until June 30, 1993.

Name of Respondent PacifiCorp	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1992
----------------------------------	---	--------------------------------	---------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

The net assets attributable to NERCO included in the carrying value of Holdings are summarized as follows:

	MILLIONS OF DOLLARS/DECEMBER 31	
	1992	1991
Current assets	\$ 151,100	\$ 198,500
Noncurrent assets	1,075,047	1,822,025
Notes payable	(381,700)	(13,900)
Current portion of long-term debt and capital lease obligations	(309,900)	(52,800)
Other current liabilities	(161,500)	(182,300)
Long-term debt	-	(660,100)
Noncurrent liabilities	(96,300)	(248,700)
Minority interest	(50,399)	(154,494)
NET ASSETS OF DISCONTINUED OPERATIONS	<u>\$ 226,348</u>	<u>\$ 708,231</u>

MONTANA OPERATION & MAINTENANCE EXPENSES

	Account Number & Title	Last Year	This Year	% Change
1				
2	Power Production Expenses			
3				
4	<u>Steam Power Generation</u>			
5				
6	Operation			
7	500 Operation Supervision & Engineering	177,075	185,412	4.71 %
8	501 Fuel	7,461,129	8,156,562	9.32 %
9	502 Steam Expenses	326,738	361,656	10.69 %
10	503 Steam from Other Sources	66,496	62,670	-5.75 %
11	504 (Less) Steam Transferred - Cr.	0	0	
12	505 Electric Expenses	137,868	163,626	18.68 %
13	506 Miscellaneous Steam Power Expenses	295,811	412,500	39.45 %
14	507 Rents	(23,553)	1,585	-106.73 %
15				
16	TOTAL Operation - Steam	8,441,564	9,344,011	10.69 %
17				
18	Maintenance			
19	510 Maintenance Supervision & Engineering	224,872	223,379	-0.66 %
20	511 Maintenance of Structures	116,007	104,074	-10.29 %
21	512 Maintenance of Boiler Plant	701,763	688,174	-1.94 %
22	513 Maintenance of Electric Plant	172,119	170,631	-0.86 %
23	514 Maintenance of Miscellaneous Steam Plant	136,343	271,564	99.18 %
24				
25	TOTAL Maintenance - Steam	1,351,104	1,457,821	7.90 %
26				
27	TOTAL Steam Power Production Expenses	9,792,668	10,801,833	10.31 %
28				
29	<u>Nuclear Power Generation</u>			
30				
31	Operation			
32	517 Operation Supervision & Engineering	31,105	25,085	-19.35 %
33	518 Nuclear Fuel Expense	4,170	6,457	54.84 %
34	519 Coolants & Water	929	869	-6.43 %
35	520 Steam Expenses	8,623	5,860	-32.05 %
36	521 Steam from Other Sources	0	0	
37	522 (Less) Steam Transferred - Cr.	0	0	
38	523 Electric Expenses	796	970	21.79 %
39	524 Miscellaneous Nuclear Power Expenses	41,645	39,073	-6.18 %
40	525 Rents	0	0	
41				
42	TOTAL Operation - Nuclear	87,269	78,313	-10.26 %
43				
44	Maintenance			
45	528 Maintenance Supervision & Engineering	8,057	10,295	27.78 %
46	529 Maintenance of Structures	4,663	2,356	-49.48 %
47	530 Maintenance of Reactor Plant Equipment	20,431	(8,475)	-141.48 %
48	531 Maintenance of Electric Plant	3,428	640	-81.32 %
49	532 Maintenance of Miscellaneous Nuclear Plant	8,062	4,382	-45.65 %
50				
51	TOTAL Maintenance - Nuclear	44,642	9,198	-79.40 %
52				
53	TOTAL Nuclear Power Production Expenses	131,911	87,511	-33.66 %

Account Number & Title		Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	<u>Hydraulic Power Generation</u>			
3				
4	Operation			
5	535 Operation Supervision & Engineering	9,708	12,068	24.31 %
6	536 Water for Power	1,341	833	-37.91 %
7	537 Hydraulic Expenses	62,102	52,084	-16.13 %
8	538 Electric Expenses	59,073	54,521	-7.71 %
9	539 Miscellaneous Hydraulic Power Gen. Expense	26,176	58,822	124.72 %
10	540 Rents	169	442	161.65 %
11				
12	TOTAL Operation - Hydraulic	158,569	178,770	12.74 %
13				
14	Maintenance			
15	541 Maintenance Supervision & Engineering	4,317	3,559	-17.57 %
16	542 Maintenance of Structures	14,359	7,568	-47.29 %
17	543 Maint. of Reservoirs, Dams & Waterways	29,898	12,895	-56.87 %
18	544 Maintenance of Electric Plant	29,504	46,028	56.00 %
19	545 Maintenance of Miscellaneous Hydro Plant	19,642	21,263	8.25 %
20				
21	TOTAL Maintenance - Hydraulic	97,719	91,313	-6.56 %
22				
23	TOTAL Hydraulic Power Production Expenses	256,288	270,083	5.38 %
24				
25	<u>Other Power Generation</u>			
26				
27	Operation			
28	546 Operation Supervision & Engineering	58	0	-100.00 %
29	547 Fuel	37,151	36,477	-1.81 %
30	548 Generation Expenses	339	0	-100.00 %
31	549 Miscellaneous Other Power Gen. Expenses	9	0	-100.00 %
32	550 Rents	0	0	
33				
34	TOTAL Operation - Other	37,557	36,477	-2.87 %
35				
36	Maintenance			
37	551 Maintenance Supervision & Engineering	56	0	-100.00 %
38	552 Maintenance of Structures	0	0	
39	553 Maintenance of Generating & Electric Plant	257	0	-100.00 %
40	554 Maintenance of Misc. Other Power Gen. Plant	130	0	-100.00 %
41				
42	TOTAL Maintenance - Other	443	0	-100.00 %
43				
44	TOTAL Other Power Production Expenses	38,000	36,477	-4.01 %
45				
46	<u>Other Power Supply Expenses</u>			
47	555 Purchased Power	2,972,001	3,828,960	28.83 %
48	556 System Control & Load Dispatching	99,995	87,375	-12.62 %
49	557 Other Expenses	227,617	398,574	75.11 %
50				
51	TOTAL Other Power Supply Expenses	3,299,613	4,314,909	30.77 %
52				
53	TOTAL Power Production Expenses	13,518,480	15,510,813	14.74 %

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	11,706	9,029	-22.86 %
4	561 Load Dispatching	66,409	77,222	16.28 %
5	562 Station Expenses	48,159	47,128	-2.14 %
6	563 Overhead Line Expenses	21,678	23,590	8.82 %
7	564 Underground Line Expenses	17	280	1571.35 %
8	565 Transmission of Electricity by Others	847,316	1,044,802	23.31 %
9	566 Miscellaneous Transmission Expenses	17,521	14,823	-15.39 %
10	567 Rents	16,733	10,062	-39.87 %
11				
12	TOTAL Operation - Transmission	1,029,538	1,226,937	19.17 %
13	Maintenance			
14	568 Maintenance Supervision & Engineering	13,361	12,956	-3.03 %
15	569 Maintenance of Structures	3,529	4,025	14.05 %
16	570 Maintenance of Station Equipment	38,363	44,142	15.06 %
17	571 Maintenance of Overhead Lines	61,172	60,349	-1.34 %
18	572 Maintenance of Underground Lines	12	21	78.15 %
19	573 Maintenance of Misc. Transmission Plant	11,419	20,291	77.70 %
20				
21	TOTAL Maintenance - Transmission	127,856	141,783	10.89 %
22				
23	TOTAL Transmission Expenses	1,157,394	1,368,720	18.26 %
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	37,154	33,309	-10.35 %
28	581 Load Dispatching	51,124	45,072	-11.84 %
29	582 Station Expenses	25,664	64,336	150.69 %
30	583 Overhead Line Expenses	115,568	160,664	39.02 %
31	584 Underground Line Expenses	61,764	108,135	75.08 %
32	585 Street Lighting & Signal System Expenses	15,353	11,332	-26.19 %
33	586 Meter Expenses	91,712	87,123	-5.00 %
34	587 Customer Installations Expenses	12,187	9,210	-24.43 %
35	588 Miscellaneous Distribution Expenses	152,706	149,626	-2.02 %
36	589 Rents	29,748	15,845	-46.74 %
37				
38	TOTAL Operation - Distribution	592,981	684,654	15.46 %
39	Maintenance			
40	590 Maintenance Supervision & Engineering	46,411	41,361	-10.88 %
41	591 Maintenance of Structures	326	1,387	324.99 %
42	592 Maintenance of Station Equipment	41,647	24,559	-41.03 %
43	593 Maintenance of Overhead Lines	472,403	462,673	-2.06 %
44	594 Maintenance of Underground Lines	68,916	83,063	20.53 %
45	595 Maintenance of Line Transformers	66,604	39,488	-40.71 %
46	596 Maintenance of Street Lighting, Signal System	9,315	12,962	39.15 %
47	597 Maintenance of Meters	25,859	27,403	5.97 %
48	598 Maintenance of Miscellaneous Dist. Plant	19,070	13,906	-27.08 %
49				
50	TOTAL Maintenance - Distribution	750,551	706,802	-5.83 %
51				
52	TOTAL Distribution Expenses	1,343,532	1,391,456	3.57 %
53				

	Account Number & Title	Last Year	This Year	% Change
1				
2	Customer Accounts Expenses			
3	Operation			
4	901 Supervision	62,321	64,167	2.96%
5	902 Meter Reading Expenses	228,414	241,259	5.62%
6	903 Customer Records & Collection Expenses	639,741	625,991	-2.15%
7	904 Uncollectible Accounts Expenses	58,960	139,439	136.50%
8	905 Miscellaneous Customer Accounts Expenses	24,033	18,387	-23.49%
9				
10	TOTAL Customer Accounts Expenses	1,013,469	1,089,243	7.48%
11				
12	Customer Service & Information Expenses			
13	Operation			
14	907 Supervision	5,425	5,315	-2.04%
15	908 Customer Assistance Expenses	88,379	105,008	18.82%
16	909 Informational & Instructional Adv. Expenses	13,576	11,464	-15.56%
17	910 Miscellaneous Customer Service & Info. Exp.	10,014	9,911	-1.03%
18				
19	TOTAL Customer Service & Info Expenses	117,394	131,697	12.18%
20				
21	Sales Expenses			
22	Operation			
23	911 Supervision	18,154	9,683	-46.66%
24	912 Demonstrating & Selling Expenses	49,176	102,083	107.59%
25	913 Advertising Expenses	59,720	24,494	-58.99%
26	916 Miscellaneous Sales Expenses	8,989	22,371	148.88%
27				
28	TOTAL Sales Expenses	136,039	158,631	16.61%
29				
30	Administrative & General Expenses			
31	Operation			
32	920 Administrative & General Salaries	1,291,371	1,269,133	-1.72%
33	921 Office Supplies & Expenses	561,932	469,110	-16.52%
34	922 (Less) Administrative Expenses Transferred - Cr.	0	0	
35	923 Outside Services Employed	150,385	174,069	15.75%
36	924 Property Insurance	52,757	157,042	197.67%
37	925 Injuries & Damages	25,061	148,383	492.10%
38	926 Employee Pensions & Benefits	953,284	1,550,280	62.63%
39	927 Franchise Requirements	212	227	6.80%
40	928 Regulatory Commission Expenses	63,321	135,324	113.71%
41	929 (Less) Duplicate Charges - Cr.	(1,166,037)	(1,653,712)	41.82%
42	930.1 General Advertising Expenses		3,181	
43	930.2 Miscellaneous General Expenses	246,368	291,162	18.18%
44	931 Rents	137,918	123,708	-10.30%
45				
46	TOTAL Operation - Admin. & General	2,316,571	2,667,907	15.17%
47	Maintenance			
48	935 Maintenance of General Plant	73,454	64,794	-11.79%
49				
50	TOTAL Administrative & General Expenses	2,390,025	2,732,701	14.34%
51				
52	TOTAL Operation & Maintenance Expenses	19,676,333	22,383,262	13.76%
53				

MONTANA TAXES OTHER THAN INCOME

	Description of Tax	Last Year	This Year	% Change
1	California - Property	39,067	38,452	-1.57%
2				
3	Oregon - Property	520,095	505,103	-2.88%
4				
5	Washington - Property	131,658	135,735	3.10%
6				
7	- Pollution Control Credit	(19,885)	(20,022)	0.69%
8				
9	Idaho - Property	45,664	32,879	-28.00%
10				
11	- KWH	165	324	96.36%
12				
13	Montana - Property	124,747	122,797	-1.56%
14				
15	- Franchise and Occupation	(884)	1,925	-317.76%
16				
17	- Regulatory Commision	48,070	72,969	51.80%
18				
19	- Energy Proceeds	4,044	3,891	-3.78%
20				
21	- Consumer Counsel	27,132	21,655	-20.19%
22				
23	Wyoming - Property	189,895	221,396	16.59%
24				
25	Utah - Property	74,283	107,303	44.45%
26				
27	Arizona - Property	39,056	86,181	120.66%
28				
29	Colorado - Property	0	46,498	
30				
31	Federal - Excise Superfund	11,490	9,275	-19.28%
32				
33	Other - Miscellaneous Taxes & License	(25)	628	
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				
53	TOTAL MT Taxes other than Income	1,234,572	1,386,989	12.35%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	J BRIDGER FUEL EXP	MINING SERVICES	97,607,316.22	1,606,323.60	1.6457%
2	CENTRALIA COAL MINE	MINING SERVICES	48,754,279.06	802,349.17	1.6457%
3	D JOHNSTON COAL MINE	MINING SERVICES	33,649,567.03	553,770.92	1.6457%
4	ENERGY WEST MINING	CONST./MAINT. CONTRACTS	17,904,248.73	294,650.22	1.6457%
5	WYODAK FUEL EXPENSE	MINING SERVICES	16,544,294.90	272,269.46	1.6457%
6	HAWKEYE CONSTRUCTION	CONST./MAINT. CONTRACTS	12,652,823.67	208,227.52	1.6457%
7	INTERNATIONAL LINE B	CONST./MAINT. CONTRACTS	12,492,559.11	205,590.05	1.6457%
8	UNION POWER CONSTRUC	CONST./MAINT. CONTRACTS	11,067,982.07	182,145.78	1.6457%
9	JOB LINE CONSTRUCTIO	CONST./MAINT. CONTRACTS	9,262,238.91	152,428.67	1.6457%
10	WESTINGHOUSE ELECTRI	CONST./MAINT. CONTRACTS	6,973,261.81	114,758.97	1.6457%
11	STOEL RIVES BOLEY JO	LEGAL	6,461,007.26	106,328.80	1.6457%
12	GENERAL ELECTRIC CO.	CONST./MAINT. CONTRACTS	6,129,703.60	100,876.53	1.6457%
13	TREES INC.	TREE TRIMMING	5,189,503.12	85,403.65	1.6457%
14	GEA POWER COOLING SY	CONST./MAINT. CONTRACTS	5,109,310.72	84,083.93	1.6457%
15	ABB COMBUSTION ENGIN	CONST./MAINT. CONTRACTS	4,466,592.43	73,506.71	1.6457%
16	INDUSTRIAL POWER CON	CONST./MAINT. CONTRACTS	3,871,341.52	63,710.67	1.6457%
17	TRI COR ASSOCIATES	CONST./MAINT. CONTRACTS	3,811,640.98	62,728.18	1.6457%
18	THOMPSON-MCDOUGALL	CONST./MAINT. CONTRACTS	3,298,268.15	54,279.60	1.6457%
19	ORACLE CORPORATION	OTHER CONSULTANTS	3,108,869.70	51,162.67	1.6457%
20	SENIOR BOILER TUBE C	OTHER	2,890,000.00	47,560.73	1.6457%
21	KIDDER PEABODY & CO	OTHER CONSULTANTS	2,677,491.01	44,063.47	1.6457%
22	NORTH AMERICAN ENERG	NESCO	2,656,094.35	43,711.34	1.6457%
23	WILSON CONSTRUCTION	CONST./MAINT. CONTRACTS	2,600,844.00	42,802.09	1.6457%
24	HENKELS & MCCOY, INC	CONST./MAINT. CONTRACTS	2,592,075.88	42,657.79	1.6457%
25	B L MONTAGUE CO, INC	CONST./MAINT. CONTRACTS	2,387,407.00	39,289.56	1.6457%
26	ENERGY WEST MINING	MINING SERVICES	2,255,634.99	37,120.99	1.6457%
27	L E MYERS CO.	CONST./MAINT. CONTRACTS	2,190,643.67	36,051.42	1.6457%
28	PACIFIC ENGINEERING	ENGINEERING	2,068,306.46	34,038.12	1.6457%
29	DEER CREEK COAL MINE	OTHER	2,043,602.11	33,631.56	1.6457%
30	UNIVERSAL TRANSPORT,	FREIGHT & CONTRACT HAULING	1,980,773.06	32,597.58	1.6457%
31	BLACK & VEATCH	ENGINEERING	1,935,317.26	31,849.52	1.6457%
32	CHRISTENSON ELECTRIC	CONST./MAINT. CONTRACTS	1,861,504.07	30,634.77	1.6457%
33	PYNCH-TURNER INCORP	CONST./MAINT. CONTRACTS	1,857,465.33	30,568.31	1.6457%
34	OSMOSE WOOD PRESERVI	CONST./MAINT. CONTRACTS	1,739,073.11	28,619.93	1.6457%
35	BONNEVILLE POWER ADM	CONST./MAINT. CONTRACTS	1,738,439.00	28,609.49	1.6457%
36	MINERICH INC	CONST./MAINT. CONTRACTS	1,671,466.30	27,507.32	1.6457%
37	FURST CONSTRUCTION O	CONST./MAINT. CONTRACTS	1,662,599.07	27,361.39	1.6457%
38	ASPLUNDH TREE EXPERT	TREE TRIMMING	1,644,136.12	27,057.55	1.6457%
39	ASHWORTH TRANSFER CO	FREIGHT & CONTRACT HAULING	1,505,188.32	24,770.88	1.6457%
40	BERMAN & O'RORKE LAW	LEGAL	1,497,365.69	24,642.15	1.6457%
41	ENGINEERING & DESIGN	OTHER	1,494,879.20	24,601.23	1.6457%
42	SARGENT & LUNDY	ENGINEERING	1,482,953.03	24,404.96	1.6457%
43	POWER CITY ELECTRIC,	CONST./MAINT. CONTRACTS	1,450,730.62	23,874.67	1.6457%
44	NEC AMERICA	CONST./MAINT. CONTRACTS	1,348,728.60	22,196.03	1.6457%
45	YOUNG & RUBICAM SAN	OTHER	1,198,153.41	19,718.01	1.6457%
46	INDUSTRIAL CONTRACTO	OTHER	1,173,790.18	19,317.06	1.6457%
47	RALPH D MCDOWELL COR	CONST./MAINT. CONTRACTS	1,130,424.98	18,603.40	1.6457%
48	INTERMOUNTAIN CONSTR	CONST./MAINT. CONTRACTS	1,126,762.50	18,543.13	1.6457%
49	DIGITAL EQUIPMENT CO	COMPUTER EQUIP. MAINTENANCE	1,117,167.06	18,385.22	1.6457%
50	I B M	COMPUTER EQUIP. MAINTENANCE	1,115,693.42	18,360.97	1.6457%
51	POWER SUBSTATIONS, I	OTHER CONSULTANTS	1,111,300.00	18,288.66	1.6457%
52	OTHERS		(26,738,491.35)	(440,035.35)	1.6457%
53	TOTAL Payments for Services		338,822,327.44	5,575,999.05	

Sch. 13

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	MONTANA VENDOR PAYMENTS (\$75, 000 or more in expenditures)				
2					
3	NORTH AMERICAN ENERGY	CONST./MAINT. CONTRACTS	107,153.80	107,153.80	100.0000%
4					
5	TREES INC.	CONST./MAINT. CONTRACTS	109,004.89	109,004.89	100.0000%
6					
7	VANALT CO., INC.	CONST./MAINT. CONTRACTS	133,635.15	133,635.15	100.0000%
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50					
51					
52					
53	TOTAL Payments for Services		349,793.84	349,793.84	

Sch. 14 POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

	Description	Total Company	Montana	% Montana
1	CITIZENS FOR FAIR CAMPAIGN FINANCING	150.00		0.00%
2	COMMITTEE TO ELECT (VARIOUS CANDIDATES)	36,350.00		0.00%
3	CONSUMERS AGAINST REGESIVE TAXATION	2,000.00		0.00%
4	FRIENDS OF PCC	2,500.00		0.00%
5	GREENSPACE MEDIA FUND	1,000.00		0.00%
6	HOUSE DEMOCRATIC CAUCUS	300.00		0.00%
7	HOUSE REPUBLICAN ORGANIZATIONAL COMM.	300.00		0.00%
8	LEADERSHIP FOR WASHIINGTON FUND	50.00		0.00%
9	OREGON CAMPAIGN INSTITUTE	500.00		0.00%
10	OREGONIANS FOR A SOUND ECONOMY	25,000.00		0.00%
11	PAC MATCHING FUND	15,000.00		0.00%
12	ROCKY MOUNTAIN PROGRAM	1,000.00		0.00%
13	RSVP FOUNDATION	100.00		0.00%
14	SENATE DEMOCRAT CAMPAIGN COMMITTEE	300.00		0.00%
15	SENATE REPUBLICAN CAMPAIGN COMMITTEE	500.00		0.00%
16	THE CAMPAIGN FOR A HATE-FREE OREGON	5,000.00		0.00%
17	THE CITIZEN'S CONVENTION	300.00		0.00%
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48	(1) PAC contributions are charged to account 426.4 and are not allocated to Montana for rate making purposes.			
49				
50				
51				
52				
53	TOTAL (1)	90,350.00		0.00%

Sch. 15 **PENSION COSTS**

	Description	Last Year	This Year	% Change
1				
2	Defined Benefit Plan?	yes	yes	
3				
4	Defined Contribution Plan?	yes	yes	
5				
6	Actuarial Cost Method	Projected Unit	Projected Unit	
7		Credit Method	Credit Method	
8	Is the Plan overfunded?	no	no	
9				
10	Accumulated Benefit Obligation	468,882,573	555,673,703	18.51%
11	Projected Benefit Obligation	522,508,757	626,822,646	19.96%
12	Fair Value of Plan Assets	444,991,945	473,284,874	6.36%
13				
14	Discount Rate for Benefit Obligations	9.00%	9.00%	0.00%
15	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
16				
17	<u>Net Periodic Pension Cost:</u>			
18	Service Cost	11,076,418	13,063,687	17.94%
19	Interest Cost	44,094,281	52,641,877	19.38%
20	Return on Plan Assets	(35,262,641)	(40,974,592)	16.20%
21	Amortization of Transition Amount	786,954	4,193,431	432.87%
22	Amortization of Gains or Losses	0	(2,157,071)	
23	Total Net Periodic Pension Cost	20,695,012	26,767,332	29.34%
24				
25	Minimum Required Contribution	0	9,197,298	
26	Actual Contribution	0	26,767,000	
27	Maximum Amount Deductible	14,322,214	60,692,363	323.76%
28	Benefit Payments	43,523,472	45,950,376	5.58%
29				
30	<u>Montana Intrastate Costs:</u>			
31	Pension Costs	253,451	310,868	
32	Pension Costs Capitalized	94,266	129,642	
33	Accumulated Pension Asset (Liability) at Year End	(1,909,231)	(2,605,228)	
34				
35	<u>Number of Company Employees:</u>			
36	Covered by the Plan	11,802	12,498	5.90%
37	Not Covered by the Plan	N/A	N/A	
38	Active	7,529	8,048	6.89%
39	Retired	3,412	3,539	3.72%

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	N/A	9.00%	
5	Expected Long-Term Return on Assets	N/A	0.00%	
6	Medical Cost Inflation Rate		12% to 6%	
7	Actuarial Cost Method		Projected Unit Credit Method	
8				
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	None			
12				
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	N/A	234,281,000	
23	Fair Value of Plan Assets	N/A	0	
24	List the amount funded through each funding method:			
25	VEBA			
26	401(h)			
27	Other			
28	Total amount funded	0	0	
29				
30	List amount that was tax deductible for each type of funding:			
31	VEBA			
32	401(h)			
33	Other			
34	Total amount that was tax deductible	0	0	
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	N/A	4,759,000	
38	Interest Cost	N/A	20,947,000	
39	Return on Plan Assets	N/A	0	
40	Amortization of Transition Obligation	N/A	11,714,000	
41	Amortization of Gains or Losses	N/A	0	
42	Total Net Periodic Post Retirement Benefit Cost	0	37,420,000	
43				
44	Benefit Cost Expensed	N/A	26,407,294	
45	Benefit Cost Capitalized	N/A	11,012,706	
46	Benefit Payments		12,600,000	
47				
48	Number of Company Employees:			
49	Covered by the Plan		11,704	
50	Not Covered by the Plan		N/A	
51	Active		8,604	
52	Retired		3,100	
53	Spouse/Dependants covered by the Plan		N/A	

	Description	Last Year	This Year	% Change
1				
2	Montana			
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)	N/A	3,855,562	
5	Fair Value of Plan Assets	N/A	0	
6	List the amount funded through each funding method:			
7	VEBA			
8	401(h)			
9	Other _____			
10	Total amount funded	0	0	
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA			
14	401(h)			
15	Other _____			
16	Total amount that was tax deductible	0	0	
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost	N/A	78,319	
20	Interest Cost	N/A	344,725	
21	Return on Plan Assets	N/A	0	
22	Amortization of Transition Obligation	N/A	192,777	
23	Amortization of Gains or Losses	N/A	0	
24	Total Net Periodic Post Retirement Benefit Cost	0	615,821	
25				
26	Benefit Cost Expensed	N/A	434,585	
27	Benefit Cost Capitalized	N/A	181,236	
28	Benefit Payments	N/A	207,358	
29				
30	Number of Company Employees:			
31	Covered by the Plan	N/A	N/A	
32	Not Covered by the Plan	N/A	N/A	
33	Active	N/A	N/A	
34	Retired	N/A	N/A	
35	Spouse/Dependants covered by the Plan	N/A	N/A	
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number:			
41	Order number:			
42				
43	Amount recovered through rates	N/A	0	

	<u>Name/Title</u>	<u>Base Salary</u>	<u>Bonuses</u>	<u>Other</u>	<u>Total</u>
1	Area Manager C Detail of "Other" - Excess Life Insurance - Vehicle Allowance - Personal Time Sold - Safety Award	70,377	6,150	11,925 761 486 10,553 125	88,452
2	District Manager B Detail of "Other" - Excess Life Insurance - Vehicle Allowance - Personal Time Sold - Safety Award	65,178	2,139	9,935 620 486 8,704 125	77,252
3	Area Operations Manager C Detail of "Other" - Excess Life Insurance - Relocation - Personal Time Sold - Safety Award	55,495	1,397	17,253 695 10,174 6,309 75	74,145
4	Area Customer Service Manager C Detail of "Other" - Excess Life Insurance - Personal Time Sold - Safety Award	62,226	2,055	5,180 800 4,255 125	69,461
5	Power Superintendent B Detail of "Other" - Excess Life Insurance - Relocation - Personal Time Sold - Safety Award	49,710	1,620	17,825 507 13,198 3,995 125	69,154
6	District Operations Manager Detail of "Other" - Excess Life Insurance - Personal Time Sold - Safety Award	52,320	1,676	12,091 165 11,851 75	66,087
7	District Manager B Detail of "Other" - Personal Time Sold - Safety Award	59,805	1,880	1,309 1,279 30	62,993
8	Line Foreman Detail of "Other" - Excess Life Insurance - Premium Time Pay - Overtime Retroactive Pay - Safety Award	55,019	1,908	2,183 2,036 10 12 125	59,110
9	Estimator A Detail of "Other" - Overtime Retroactive Pay	55,330	1,718	1 1	57,049
10	Lineman Detail of "Other" - Excess Life Insurance - Premium Time Pay - Overtime Retroactive Pay - Safety Award	53,944	1,601	1,461 287 1,108 16 50	57,006

	<u>Name/Title</u>	<u>Base Salary</u>	<u>Bonuses</u>	<u>Other</u>	<u>Total</u>
1	Joel B. Rogers Area Manager C	70,377	6,150	11,925	88,452
2	James M. Redman District Manager B	65,178	2,139	9,935	77,252
3	Donald M. Jordan Area Operations Manager C	55,495	1,397	17,253	74,145
4	Lawrence C. Delibero Area Customer Service Manager C	62,226	2,055	5,180	69,461
5	Coyd A. Fouts, Jr. Power Superintendent B	49,710	1,620	17,825	69,154
6	Dan L. Olmstead District Operations Manager	52,320	1,676	12,091	66,087
7	Lucy S. Tyler District Manager B	59,805	1,880	1,309	62,993
8	Willeam H. Arthur Line Foreman	55,019	1,908	2,183	59,110
9	Eugene R. Drager Estimator A	55,330	1,718	1	57,049
10	Dennis L. Gosney Lineman	53,944	1,601	1,461	57,006

	Account Title	Last Year	This Year	% Change
1	Assets and Other Debits			
2	Utility Plant			
3	101 Electric Plant in Service	8,007,328,299	8,399,047,917	5 %
4	101.1 Property Under Capital Leases	20,505,744	18,958,044	(8) %
5	102 Electric Plant Purchased or Sold	450,227,778	710,328,780	58 %
6	103 Experimental Electric Plant Unclassified	1,286,190	1,286,190	
7	104 Electric Plant Leased to Others			
8	105 Electric Plant Held for Future Use	9,720,761	6,709,964	(31) %
9	106 Completed Constr. Not Classified – Electric	36,323,956	43,032,492	18 %
10	107 Construction Work in Progress – Electric	243,109,328	268,277,915	10 %
11	108 (Less) Accumulated Depreciation	2,477,396,364	2,630,596,417	6 %
12	111 (Less) Accumulated Amortization	44,190,275	53,971,709	22 %
13	114 Electric Plant Acquisition Adjustments	18,935,142	14,399,618	(24) %
14	115 (Less) Accum. Amort. Elec. Acq. Adj.			
15	118–119 Other Utility Plant – Net	1,236,485	1,206,344	(2) %
16	120 Nuclear Fuel (Net)	2,382,611	80,360	(97) %
17	TOTAL Utility Plant	6,269,469,655	6,778,759,498	8 %
18				
19	Other Property & Investments			
20	121 Nonutility Property	15,718,248	7,693,205	(51) %
21	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	932,482	1,003,415	8 %
22	123 Investments in Associated Companies		6,107,928	
23	123.1 Investments in Subsidiary Companies	1,373,185,798	784,660,938	(43) %
24	124 Other Investments	14,945,551	18,632,235	25 %
25	125 Sinking Funds			
26	128 Other Special Funds	26,861	77,550,142	288,609 %
27	TOTAL Other Property & Investments	1,402,943,976	893,641,033	(36) %
28				
29	Current & Accrued Assets			
30	131 Cash	(24,368,216)	(40,297,075)	65 %
31	132–134 Special Deposits	2,017,314	867,664	(57) %
32	135 Working Funds	1,775,147	1,405,679	(21) %
33	136 Temporary Cash Investments	20,755,000	25,600,000	23 %
34	141 Notes Receivable	1,343,027	1,256,047	(6) %
35	142 Customer Accounts Receivable	176,491,277	181,449,297	3 %
36	143 Other Accounts Receivable	42,197,054	70,203,331	66 %
37	144 (Less) Accum. Provision for Uncollectible Accts.	7,848,846	9,495,204	21 %
38	145 Notes Receivable – Associated Companies	1,967,792	490,262	(75) %
39	146 Accounts Receivable – Associated Companies	1,172,464	2,058,124	76 %
40	151 Fuel Stock	71,098,556	70,018,817	(2) %
41	152 Fuel Stock Expenses Undistributed			
42	153 Residuals			
43	154 Plant Materials and Operating Supplies	132,215,645	120,064,866	(9) %
44	155 Merchandise	660,897	104,493	(84) %
45	156 Other Material & Supplies	20,750		(100) %
46	157 Nuclear Materials Held for Sale			
47	163 Stores Expense Undistributed	8,315,338	5,289,480	(36) %
48	165 Prepayments	48,108,799	41,884,241	(13) %
49	171 Interest & Dividends Receivable	3,385,909	1,546,037	(54) %
50	172 Rents Receivable		37,150	
51	173 Accrued Utility Revenues	109,658,750	107,454,859	(2) %
52	174 Miscellaneous Current & Accrued Assets	58,127,747	26,777,559	(54) %
53	TOTAL Current & Accrued Assets	647,094,404	606,715,627	(6) %

	<u>Account Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
1	Assets and Other Debits (cont.)			
2				
3	Deferred Debits			
4				
5	181 Unamortized Debt Expense	11,696,828	15,216,218	30 %
6	182.1 Extraordinary Property Losses	4,964,165	3,899,777	(21) %
7	182.2 Unrecovered Plant & Regulatory Study Costs	374,591	29,936,179	7,892 %
8	182.3 Regulatory Assets			
9	183 Prelim. Survey & Investigation Charges	7,845,134	4,517,077	(42) %
10	184 Clearing Accounts			
11	185 Temporary Facilities	246,036	233,543	(5) %
12	186 Miscellaneous Deferred Debits	383,229,460	262,070,721	(32) %
13	187 Deferred Losses from Disposition of Util. Plant			
14	188 Research, Devel. & Demonstration Expend.			
15	189 Unamortized Loss on Reacquired Debt	42,246,427	70,376,742	67 %
16	190 Accumulated Deferred Income Taxes	29,318,985	42,522,941	45 %
17	TOTAL Deferred Debits	479,921,626	428,773,198	(11) %
18				
19	TOTAL Assets & Other Debits	8,799,429,661	8,707,889,356	(1) %

	<u>Account Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
20	Liabilities and Other Credits			
21				
22				
23	Proprietary Capital			
24	201 Common Stock Issued	2,637,528,658	2,817,115,745	7 %
25	202 Common Stock Subscribed			
26	204 Preferred Stock Issued	492,360,450	636,360,450	29 %
27	205 Preferred Stock Subscribed			
28	207 Premium on Capital Stock			
29	211 Miscellaneous Paid-In Capital			
30	212 Installments Received on Capital Stock	(13,728)	201,951	(1,571) %
31	213 (Less) Discount on Capital Stock			
32	214 (Less) Capital Stock Expense	35,224,759	40,943,989	16 %
33	215 Appropriated Retained Earnings	3,182,660	3,182,660	
34	216 Unappropriated Retained Earnings	987,512,370	197,549,488	(80) %
35	217 (Less) Reacquired Capital Stock	370,000	280,000	(24) %
36	TOTAL Proprietary Capital	4,084,975,651	3,695,634,283	(10) %
37				
38	Long Term Debt			
39				
40	221 Bonds	2,840,476,108	3,017,508,509	6 %
41	222 (Less) Reacquired Bonds			
42	223 Advances from Associated Companies			
43	224 Other Long Term Debt			
44	225 Unamortized Premium on Long Term Debt	16,453,291	14,392,297	(13) %
45	226 (Less) Unamort. Discount on L-Term Debt-Dr.	5,439,279	3,408,263	(37) %
46	TOTAL Long Term Debt	2,851,490,120	3,028,492,543	6 %

	<u>Account Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
1				
2	Total Liabilities and Other Credits (cont.)			
3				
4	Other Noncurrent Liabilities			
5				
6	227 Obligations Under Cap. Leases – Noncurrent	19,713,154	17,971,653	(9) %
7	228.1 Accumulated Provision for Property Insurance	3,421,540	3,980,294	16 %
8	228.2 Accumulated Provision for Injuries & Damages	4,108,278	3,680,440	(10) %
9	228.3 Accum. Provision for Pensions & Benefits			
10	228.4 Accumulated Misc. Operating Provisions	171,318,212	151,506,464	(12) %
11	229 Accumulated Provision for Rate Refunds	1,512,000	1,700,000	12 %
12	TOTAL Other Noncurrent Liabilities	200,073,184	178,838,851	(11) %
13				
14	Current & Accrued Liabilities			
15				
16	231 Notes Payable	196,940,862	362,622,634	84 %
17	232 Accounts Payable	136,846,161	201,375,063	47 %
18	233 Notes Payable to Associated Companies	10,504,679	19,176,263	83 %
19	234 Accounts Payable to Associated Companies	10,103,541	10,437,670	3 %
20	235 Customer Deposits	7,785,793	8,612,086	11 %
21	236 Taxes Accrued	111,878,764	61,047,317	(45) %
22	237 Interest Accrued	79,097,354	78,597,727	(1) %
23	238 Dividends Declared	104,055,629	114,201,141	10 %
24	239 Matured Long Term Debt	1,792,200	15,450	(99) %
25	240 Matured Interest	126,114	72,214	(43) %
26	241 Tax Collections Payable	9,850,137	7,075,057	(28) %
27	242 Miscellaneous Current & Accrued Liabilities	100,913,329	80,605,066	(20) %
28	243 Obligations Under Capital Leases – Current	320,145	275,339	(14) %
29	TOTAL Current & Accrued Liabilities	770,214,708	944,113,027	23 %
30				
31	Deferred Credits			
32				
33	252 Customer Advances for Construction	13,841,919	13,917,753	1 %
34	253 Other Deferred Credits	95,089,743	89,293,912	(6) %
35	254 Regulatory Liabilities			
36	255 Accumulated Deferred Investment Tax Credit	201,067,410	191,597,943	(5) %
37	256 Deferred Gains from Disposition Of Util. Plant			
38	257 Unamortized Gain on Reacquired Debt	5,858,606	4,824,417	(18) %
39	281–283 Accumulated Deferred Income Taxes	576,818,320	643,624,605	12 %
40	TOTAL Deferred Credits	892,675,998	943,258,630	6 %
41				
42	TOTAL Liabilities & Other Credits	8,799,429,661	8,790,337,334	

Sch. 19	MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)			P. 1 of 3
	Account Number & Title	Last Year	This Year	% Change
1				
2	Intangible Plant			
3				
4	301 Organization	462,256	460,690	-0.34%
5	302 Franchises & Consents	78,233	75,719	-3.21%
6	303 Miscellaneous Intangible Plant	848,476	891,138	5.03%
7				
8	TOTAL Intangible Plant	1,388,965	1,427,548	2.78%
9				
10	Production Plant			
11				
12	Steam Production			
13				
14	310 Land & Land Rights	494,137	526,342	6.52%
15	311 Structures & Improvements	7,797,453	7,629,278	-2.16%
16	312 Boiler Plant Equipment	28,447,114	27,844,978	-2.12%
17	313 Engines & Engine Driven Generators	0	0	
18	314 Turbogenerator Units	6,691,931	6,771,399	1.19%
19	315 Accessory Electric Equipment	3,070,145	3,004,541	-2.14%
20	316 Miscellaneous Power Plant Equipment	595,686	620,416	4.15%
21				
22	TOTAL Steam Production Plant	47,096,466	46,396,954	-1.49%
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights	867	0	-100.00%
27	321 Structures & Improvements	143,810	0	-100.00%
28	322 Reactor Plant Equipment	170,152	0	-100.00%
29	323 Turbogenerator Units	127,066	0	-100.00%
30	324 Accessory Electric Equipment	56,141	0	-100.00%
31	325 Miscellaneous Power Plant Equipment	32,805	0	-100.00%
32				
33	TOTAL Nuclear Production Plant	530,841	0	-100.00%
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights	327,088	319,260	-2.39%
38	331 Structures & Improvements	752,313	773,943	2.88%
39	332 Reservoirs, Dams & Waterways	4,944,474	4,988,148	0.88%
40	333 Water Wheels, Turbines & Generators	1,115,528	1,120,894	0.48%
41	334 Accessory Electric Equipment	371,294	380,223	2.40%
42	335 Miscellaneous Power Plant Equipment	75,693	89,633	18.42%
43	336 Roads, Railroads & Bridges	150,042	152,929	1.92%
44				
45	TOTAL Hydraulic Production Plant	7,736,432	7,825,031	1.15%
46				
47				
48				
49				
50				
51				
52				

	Account Number & Title	Last Year	This Year	% Change
1				
2	Production Plant (cont.)			
3				
4	Other Production			
5				
6	340 Land & Land Rights	0	0	
7	341 Structures & Improvements	0	0	
8	342 Fuel Holders, Producers & Accessories	0	0	
9	343 Prime Movers	1445	0	-100.00%
10	344 Generators	28	0	-100.00%
11	345 Accessory Electric Equipment	953	0	-100.00%
12	346 Miscellaneous Power Plant Equipment	0	0	
13				
14	TOTAL Other Production Plant	2,426	0	-100.00%
15				
16	TOTAL Production Plant	55,366,165	54,221,985	-2.07%
17				
18	Transmission Plant			
19				
20	350 Land & Land Rights	719,176	691,796	-3.81%
21	352 Structures & Improvements	357,859	345,570	-3.43%
22	353 Station Equipment	6,783,363	7,539,360	11.14%
23	354 Towers & Fixtures	5,145,108	5,342,391	3.83%
24	355 Poles & Fixtures	3,037,883	3,123,138	2.81%
25	356 Overhead Conductors & Devices	7,432,545	7,455,473	0.31%
26	357 Underground Conduit	192	210	9.64%
27	358 Underground Conductors & Devices	354	304	-14.19%
28	359 Roads & Trails	65,926	55,757	-15.43%
29				
30	TOTAL Transmission Plant	23,542,406	24,554,000	4.30%
31				
32	Distribution Plant			
33				
34	360 Land & Land Rights	219,549	217,526	-0.92%
35	361 Structures & Improvements	412,467	415,636	0.77%
36	362 Station Equipment	7,943,647	7,313,876	-7.93%
37	363 Storage Battery Equipment	0	0	
38	364 Poles, Towers & Fixtures	7,832,091	7,923,870	1.17%
39	365 Overhead Conductors & Devices	8,193,821	8,273,699	0.97%
40	366 Underground Conduit	1,155,465	1,368,393	18.43%
41	367 Underground Conductors & Devices	2,015,228	2,190,422	8.69%
42	368 Line Transformers	11,376,688	12,181,076	7.07%
43	369 Services	4,369,688	4,439,634	1.60%
44	370 Meters	1,599,266	1,677,597	4.90%
45	371 Installations on Customers' Premises	184,484	170,135	-7.78%
46	372 Leased Property on Customers' Premises	0	0	
47	373 Street Lighting & Signal Systems	496,512	486,777	-1.96%
48				
49	TOTAL Distribution Plant	45,798,906	46,658,641	1.88%
50				
51				
52				

	<u>Account Number & Title</u>	<u>Last Year</u>	<u>This Year</u>	<u>% Change</u>
1				
2	General Plant			
3				
4	389 Land & Land Rights	17,795	20,032	12.57%
5	390 Structures & Improvements	1,653,268	1,421,966	-13.99%
6	391 Office Furniture & Equipment	1,375,683	1,802,653	31.04%
7	392 Transportation Equipment	276,186	320,368	16.00%
8	393 Stores Equipment	80,258	82,390	2.66%
9	394 Tools, Shop & Garage Equipment	358,774	431,248	20.20%
10	395 Laboratory Equipment	530,271	580,533	9.48%
11	396 Power Operated Equipment	367,490	394,970	7.48%
12	397 Communication Equipment	798,497	857,438	7.38%
13	398 Miscellaneous Equipment	30,519	32,322	5.91%
14	399 Other Tangible Property	5,958,294	5,736,346	-3.73%
15				
16	TOTAL General Plant	11,447,035	11,680,265	2.04%
17				
18	TOTAL (Account 101)	137,543,477	138,542,438	0.73%
19				
20	102 Communication Equipment	0	0	
21	103 Miscellaneous Equipment	37,077	35,771	-3.52%
22	106 Other Tangible Property	5,584,282	10,944,030	95.98%
23				
24	TOTAL Electric Plant in Service	143,164,836	149,522,239	4.44%

Sch. 20 MONTANA DEPRECIATION SUMMARY					
	Functional Plant Classification	Plant Cost	Accumulated Depreciation		Current
			Last Year Bal.	This Year Bal.	Avg. Rate
1					
2	Steam Production		16,147,000	16,815,708	3.08%
3	Nuclear Production		228,000	0	3.98%
4	Hydraulic Production		2,780,000	2,773,099	1.54%
5	Other Production		6,000	8,297	3.08%
6	Transmission		6,683,000	6,774,311	2.36%
7	Distribution		13,165,000	13,589,887	3.32%
8	General		3,884,000	3,996,616	5.89%
9	TOTAL	0	42,893,000	43,957,917	

Sch. 21 MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)					
	Account		Last Year Bal.	This Year Bal.	% Change
1					
2	151	Fuel Stock	1,203,123	1,081,654	-10.10%
3	152	Fuel Stock Expenses Undistributed			
4	153	Residuals			
5	154	Plant Materials & Operating Supplies:			
6		Assigned to Construction (Estimated)			
7		Assigned to Operations & Maintenance			
8		Production Plant (Estimated)	1,153,008	1,134,519	-1.60%
9		Transmission Plant (Estimated)	243,298	247,241	1.62%
10		Distribution Plant (Estimated)	496,524	388,888	-21.68%
11		Assigned to Other	13,576	9,793	-27.87%
12	155	Merchandise			
13	156	Other Materials & Supplies			
14	157	Nuclear Materials Held for Sale			
15	163	Stores Expense Undistributed	119,898	87,050	-27.40%
16					
17	TOTAL Materials & Supplies		3,229,427	2,949,145	-8.68%

Sch. 22 MONTANA REGULATORY CAPITAL STRUCTURE & COSTS					
	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	89.6.17			
2	Order Number	5432			
3					
4	Common Equity		35.20%	12.30%	4.33%
5	Preferred Stock		7.60%	8.35%	0.63%
6	Long Term Debt		57.20%	8.45%	4.83%
7	Other		0.00%	0.00%	0.00%
8	TOTAL		100.00%		9.80%
9					
10	Actual at Year End				
11					
12	Common Equity		51.79%	12.10%	6.27%
13	Preferred Stock		7.10%	6.40%	0.45%
14	Long Term Debt		41.11%	8.44%	3.47%
15	Other		0.00%	0.00%	0.00%
16	TOTAL		100.00%		10.19%

STATEMENT OF CASH FLOWS

	Description	This year	Last Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	Cash Flows from Operating Activities:			
5	Net Income	(340,925,328)	506,696,910	(249) %
6	Depreciation	269,976,120	244,096,126	(10) %
7	Amortization	16,656,468	11,917,163	(28) %
8	Deferred Income Taxes – Net	53,602,328	(18,640,806)	(135) %
9	Investment Tax Credit Adjustments – Net	(9,469,467)	(9,115,328)	(4) %
10	Change in Operating Receivables – Net	(22,125,449)	(9,130,733)	(59) %
11	Change in Materials, Supplies & Inventories – Net	4,370,335	271,106	(94) %
12	Change in Operating Payables & Accrued Liabilities – Net	17,083,086	30,678,759	80 %
13	Allowance for Funds Used During Construction (AFUDC)	(7,327,515)	(7,925,747)	8 %
14	Change in Other Assets & Liabilities – Net	43,858,622	100,066,450	128 %
15	Other Operating Activities (explained on attached page)	587,850,509	(135,159,703)	(123) %
16	Net Cash Provided by/(Used in) Operating Activities	613,549,709	713,754,197	16 %
17				
18	Cash Inflows/Outflows From Investment Activities:			
19	Construction/Acquisition of Property, Plant and Equipment	(581,608,580)	(770,028,776)	32 %
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	2,974,015	4,628,366	56 %
23	Investments In and Advances to Affiliates	674,351	(80,052,000)	(11,971) %
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	7,935,478	8,076,069	2 %
27	Net Cash Provided by/(Used in) Investing Activities	(570,024,736)	(837,376,341)	47 %
28				
29	Cash Flows from Financing Activities:			
30	Proceeds from Issuance of:			
31	Long-Term Debt	710,308,943	663,215,135	(7) %
32	Preferred Stock	195,189,483	98,428,301	(50) %
33	Common Stock	178,226,151	197,689,704	11 %
34	Other: Intercompany Borrowings	10,149,114	52,498,927	417 %
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(820,059,354)	(451,651,023)	(45) %
39	Preferred Stock	(56,000,000)		(100) %
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt	165,681,772	(41,412,079)	(125) %
43	Dividends on Preferred Stock	(35,167,657)	(26,106,307)	(26) %
44	Dividends on Common Stock	(404,456,402)	(382,965,517)	(5) %
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(56,127,950)	109,697,141	(295) %
47				
48				
49	Net Increase/(Decrease) in Cash and Cash Equivalents	(12,602,977)	(13,925,003)	10 %
50	Cash and Cash Equivalents at Beginning of Year	179,245	14,104,248	7,769 %
51	Cash and Cash Equivalents at End of Year	(12,423,732)	179,245	(101) %

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	FIRST MORTGAGE BONDS:								
2	4-1/2% Series due 4/1/93	4/63	4/93	15,000,000	11,461,782	11,442,000	N.A.	513,631	4.48%
3	4-5/8% Series due 8/1/93	8/63	8/93	30,000,000	19,610,845	19,666,000	N.A.	912,896	4.66%
4	4-5/8% Series due 8/1/94	8/64	8/94	15,000,000	13,537,798	13,400,000	N.A.	611,308	4.52%
5	4-5/8% Series due 10/1/94	10/64	10/94	30,000,000	19,936,067	20,261,000	N.A.	957,535	4.80%
6	5% Series due 10/1/95	10/65	10/95	30,000,000	14,026,006	14,168,000	N.A.	717,609	5.12%
7	9-3/8% Yen Fin due 7/22/97	7/87	7/97	50,000,000	49,668,437	50,000,000	N.A.	1,840,700	3.71%
8	7% Series due 3/1/98	3/68	3/98	20,000,000	15,982,729	16,000,000	N.A.	1,121,440	7.02%
9	8% Series due 5/1/99	5/69	5/99	25,000,000	20,985,540	21,057,000	N.A.	1,690,877	8.06%
10	7-7/8% Series due 2/1/01	2/71	2/01	40,000,000	27,522,635	28,024,000	N.A.	2,251,448	8.18%
11	8% Series due 10/1/01	10/71	10/01	35,000,000	25,428,951	25,882,000	N.A.	2,111,195	8.30%
12	7-1/2% Series due 5/1/02	5/72	5/02	25,000,000	20,079,174	20,310,000	N.A.	1,542,951	7.68%
13	7-3/4% Series due 10/1/02	10/72	10/02	30,000,000	19,434,644	19,744,000	N.A.	1,557,209	8.01%
14	Adjust. Rate Series due 11/1/02	9/82	11/02	50,000,000	13,116,905	13,234,000	N.A.	1,337,163	10.19%
15	8-3/8% Series due 1/1/04	1/74	1/04	60,000,000	52,154,175	52,695,000	N.A.	4,463,267	8.56%
16	8-3/4% Series due 4/1/06	4/76	4/06	32,000,000	31,628,674	32,000,000	N.A.	2,835,520	8.97%
17	8-3/8% Series due 9/1/06	9/76	9/06	40,000,000	39,689,106	40,000,000	N.A.	3,378,800	8.51%
18	8-5/8% Series due 12/1/06	12/76	12/06	50,000,000	44,781,673	45,075,000	N.A.	3,915,215	8.74%
19	8-1/2% Series due 3/1/07	3/77	3/07	55,000,000	54,884,275	55,000,000	N.A.	4,686,000	8.54%
20	8-1/4% Series due 9/1/07	9/77	9/07	50,000,000	33,055,899	33,175,000	N.A.	2,747,885	8.31%
21	8-7/8% Series due 11/1/07	11/77	11/07	100,000,000	91,978,513	93,345,000	N.A.	8,416,919	9.15%
22	8.271% Series due 10/1/10	4/92	10/10	48,972,000	47,285,288	47,342,000	N.A.	3,921,811	8.29%
23	7.978% Series due 10/1/11	4/92	10/11	4,422,000	4,252,899	4,258,000	N.A.	340,214	8.00%
24	8.493% Series due 10/1/12	4/92	10/12	19,772,000	19,160,020	19,183,000	N.A.	1,631,706	8.52%
25	8.797% Series due 10/1/13	4/92	10/13	16,203,000	15,733,130	15,752,000	N.A.	1,387,751	8.82%
26	8.734% Series due 10/1/14	4/92	10/14	28,218,000	27,455,071	27,488,000	N.A.	2,404,100	8.76%
27	8.294% Series due 10/1/15	4/92	10/15	46,946,000	45,727,156	45,782,000	N.A.	3,802,653	8.32%
28	8.635% Series due 10/1/16	4/92	10/16	18,750,000	18,296,056	18,318,000	N.A.	1,583,957	8.66%
29	8-3/4% Series due 12/1/16	12/86	12/16	92,000,000	92,000,000	92,000,000	N.A.	8,050,000	8.75%
30	8.470% Series due 10/1/17	4/92	10/17	19,609,000	19,156,025	19,179,000	N.A.	1,626,763	8.49%
31									
32	Total First Mortgage Bonds			1,076,892,000	908,029,473	913,780,000		72,358,523	7.97%
33									
34									

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
35	SECURED MEDIUM-TERM NOTES:								
36	7.79% Ser. B due 1/29/93	1/91	1/93	10,000,000	9,955,352	10,000,000	N.A.	803,600	8.07%
37	8.15% Ser. B due 12/30/93	12/90	12/93	1,000,000	1,048,051	1,000,000	N.A.	63,650	6.07%
38	8.11% Ser. B due 1/18/94	1/91	1/94	4,000,000	3,976,141	4,000,000	N.A.	333,560	8.39%
39	8.07% Ser. B due 2/1/94	1/91	2/94	10,000,000	9,945,352	10,000,000	N.A.	827,900	8.32%
40	8-7/8% Ser. A due 6/15/94	6/89	6/94	10,000,000	10,465,515	10,000,000	N.A.	773,500	7.39%
41	8.47% Ser. B due 1/17/95	1/91	1/95	5,000,000	4,965,176	5,000,000	N.A.	434,000	8.74%
42	8.41% Ser. B due 2/1/95	1/91	2/95	10,000,000	9,930,352	10,000,000	N.A.	862,000	8.68%
43	8.59% Ser. B due 12/26/95	12/90	12/95	3,000,000	3,139,655	3,000,000	N.A.	223,740	7.13%
44	8.60% Ser. B due 12/28/95	12/90	12/95	2,500,000	2,616,379	2,500,000	N.A.	186,675	7.13%
45	8.60% Ser. B due 1/25/96	1/91	1/96	1,000,000	993,535	1,000,000	N.A.	87,620	8.82%
46	8.57% Ser. B due 2/1/96	1/91	2/96	11,000,000	10,928,887	11,000,000	N.A.	960,520	8.79%
47	8.55% Ser. B due 2/1/96	1/91	2/96	3,000,000	2,977,605	3,000,000	N.A.	262,110	8.80%
48	8.69% Ser. C due 7/16/96	7/91	7/96	8,500,000	8,442,477	8,500,000	N.A.	753,100	8.92%
49	8.65% Ser. B due 7/17/96	7/91	7/96	1,000,000	994,982	1,000,000	N.A.	87,760	8.82%
50	8.49% Ser. C due 8/15/96	8/91	8/96	14,050,000	13,954,918	14,050,000	N.A.	1,216,730	8.72%
51	8.43% Ser. A due 9/2/96	8/89	9/96	5,000,000	5,228,591	5,000,000	N.A.	378,800	7.24%
52	6.96% Ser. D due 1/22/97	2/92	1/97	1,000,000	912,241	1,000,000	N.A.	91,880	10.07%
53	7.00% Ser. D due 1/27/97	1/92	1/97	15,000,000	14,001,525	15,000,000	N.A.	1,300,350	9.29%
54	7.00% Ser. D due 1/27/97	1/92	1/97	20,000,000	18,668,701	20,000,000	N.A.	1,733,800	9.29%
55	6.99% Ser. D due 2/3/97	1/92	2/97	1,500,000	1,400,152	1,500,000	N.A.	129,870	9.28%
56	6.09% Ser. E due 4/15/97	10/92	4/97	2,000,000	1,791,000	2,000,000	N.A.	179,260	10.01%
57	8.87% Ser. A due 6/20/97	6/91	6/97	20,000,000	19,909,544	20,000,000	N.A.	1,793,800	9.01%
58	8.85% Ser. A due 6/20/97	6/91	6/97	15,000,000	14,917,158	15,000,000	N.A.	1,345,650	9.02%
59	8.78% Ser. B due 6/30/97	6/91	6/97	7,000,000	6,961,340	7,000,000	N.A.	623,070	8.95%
60	8.84% Ser. B due 7/2/97	7/91	7/97	2,000,000	1,988,965	2,000,000	N.A.	179,220	9.01%
61	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
62	6.12% Ser. E due 9/29/97	9/92	9/97	3,500,000	3,457,000	3,500,000	N.A.	224,385	6.49%
63	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
64	6.12% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	629,800	6.35%
65	6.14% Ser. E due 9/29/97	9/92	9/97	10,000,000	9,924,500	10,000,000	N.A.	631,800	6.37%
66	5.88% Ser. E due 10/15/97	10/92	10/97	1,000,000	907,888	1,000,000	N.A.	76,010	8.37%
67	6.00% Ser. E due 10/15/97	10/92	10/97	2,300,000	2,058,143	2,300,000	N.A.	183,770	8.93%
68	5.88% Ser. E due 10/15/97	10/92	10/97	12,000,000	10,620,435	12,000,000	N.A.	967,320	9.11%

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual, Net Cost Inc. Prem/Disc.	Total Cost %
69	SECURED MEDIUM-TERM NOTES (Cont.):								
70	8.75% Ser. A due 2/12/98	2/91	2/98	5,000,000	4,957,676	5,000,000	N.A.	445,750	8.99%
71	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,673,027	15,000,000	N.A.	1,337,250	9.11%
72	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,873,027	15,000,000	N.A.	1,355,550	9.11%
73	8.75% Ser. B due 2/12/98	2/91	2/98	15,000,000	14,780,527	15,000,000	N.A.	1,376,850	9.32%
74	8.75% Ser. A due 2/12/98	2/91	2/98	10,000,000	9,915,352	10,000,000	N.A.	891,500	8.99%
75	8.81% Ser. C due 3/5/98	8/91	3/98	7,000,000	6,949,128	7,000,000	N.A.	626,640	9.02%
76	8.94% Ser. A due 6/25/98	6/91	6/98	15,000,000	14,909,658	15,000,000	N.A.	1,358,700	9.11%
77	8.90% Ser. C due 6/30/98	6/91	6/98	25,000,000	24,805,815	25,000,000	N.A.	2,263,000	9.12%
78	8.95% Ser. A due 6/30/98	6/91	6/98	5,000,000	4,972,386	5,000,000	N.A.	452,900	9.11%
79	8.95% Ser. A due 6/30/98	6/91	6/98	20,000,000	19,879,544	20,000,000	N.A.	1,813,600	9.12%
80	8.96% Ser. A due 7/3/98	7/91	7/98	8,000,000	7,951,860	8,000,000	N.A.	726,240	9.13%
81	8.94% Ser. C due 7/6/98	7/91	7/98	5,000,000	4,961,163	5,000,000	N.A.	454,600	9.16%
82	8.89% Ser. C due 7/20/98	7/91	7/98	5,000,000	4,961,163	5,000,000	N.A.	452,100	9.11%
83	8.82% Ser. C due 8/3/98	8/91	8/98	5,000,000	4,961,163	5,000,000	N.A.	448,600	9.04%
84	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,970,930	4,000,000	N.A.	359,280	9.05%
85	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,930	4,000,000	N.A.	358,880	9.04%
86	8.83% Ser. C due 9/1/98	8/91	9/98	4,000,000	3,968,330	4,000,000	N.A.	359,280	9.05%
87	8.83% Ser. C due 9/1/98	8/91	9/98	18,000,000	17,860,187	18,000,000	N.A.	1,616,760	9.05%
88	7.45% Ser. D due 1/22/99	1/92	1/99	10,000,000	9,324,350	10,000,000	N.A.	876,200	9.40%
89	7.45% Ser. D due 1/22/99	1/92	1/99	5,000,000	4,662,175	5,000,000	N.A.	458,250	9.83%
90	7.35% Ser. D due 2/1/99	1/92	2/99	4,000,000	3,729,740	4,000,000	N.A.	346,280	9.28%
91	7.45% Ser. D due 2/4/99	1/92	2/99	20,000,000	18,224,829	20,000,000	N.A.	1,839,600	10.09%
92	7.54% Ser. D due 2/15/99	2/92	2/99	15,000,000	13,668,621	15,000,000	N.A.	1,393,950	10.20%
93	7.50% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	462,550	10.15%
94	7.49% Ser. D due 2/15/99	2/92	2/99	30,000,000	27,337,242	30,000,000	N.A.	2,772,000	10.14%
95	7.46% Ser. D due 2/15/99	2/92	2/99	10,000,000	9,112,414	10,000,000	N.A.	920,800	10.10%
96	7.45% Ser. D due 2/15/99	2/92	2/99	20,000,000	18,224,829	20,000,000	N.A.	1,839,600	10.09%
97	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	457,250	10.04%
98	7.40% Ser. D due 2/15/99	2/92	2/99	5,000,000	4,556,207	5,000,000	N.A.	457,250	10.04%
99	9-1/2% Ser. A due 5/20/99	5/89	5/99	60,000,000	62,718,089	60,000,000	N.A.	5,285,400	8.43%
100	9.48% Ser. A due 5/25/99	5/89	5/99	15,000,000	15,680,772	15,000,000	N.A.	1,318,350	8.41%
101	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	N.A.	1,321,200	8.43%
102	9-1/2% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,680,772	15,000,000	N.A.	1,321,200	8.43%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
103	SECURED MEDIUM-TERM NOTES (Cont.):								
104	9.40% Ser. A due 6/1/99	5/89	6/99	15,000,000	15,740,422	15,000,000	N.A.	1,297,800	8.25%
105	8.55% Ser. A due 8/10/99	8/89	8/99	2,000,000	2,090,603	2,000,000	N.A.	157,740	7.55%
106	8.59% Ser. A due 9/1/99	8/89	9/99	10,000,000	10,457,182	10,000,000	N.A.	792,000	7.57%
107	6.51% Ser. E due 9/23/99	9/92	9/99	15,000,000	14,884,500	15,000,000	N.A.	997,350	6.70%
108	6.53% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	N.A.	336,550	6.81%
109	6.54% Ser. E due 9/27/99	9/92	9/99	5,000,000	4,944,500	5,000,000	N.A.	337,100	6.82%
110	6.55% Ser. E due 9/28/99	9/92	9/99	1,200,000	1,167,300	1,200,000	N.A.	84,600	7.25%
111	6.86% Ser. E due 9/11/00	9/92	9/00	10,000,000	9,914,500	10,000,000	N.A.	700,100	7.06%
112	6.55% Ser. E due 9/15/00	9/92	9/00	5,000,000	4,944,500	5,000,000	N.A.	336,600	6.81%
113	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	N.A.	1,806,000	9.11%
114	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,825,703	20,000,000	N.A.	1,806,800	9.11%
115	8.88% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,830,703	20,000,000	N.A.	1,802,800	9.09%
116	8.90% Ser. B due 2/15/01	2/91	2/01	20,000,000	19,830,703	20,000,000	N.A.	1,806,800	9.11%
117	9.10% Ser. A due 3/1/01	6/91	3/01	5,000,000	4,969,886	5,000,000	N.A.	459,650	9.25%
118	9.12% Ser. C due 7/5/01	7/91	7/01	5,000,000	4,959,913	5,000,000	N.A.	462,250	9.32%
119	9.12% Ser. C due 7/5/01	7/91	7/01	10,000,000	9,919,826	10,000,000	N.A.	924,500	9.32%
120	9.06% Ser. B due 7/9/01	7/91	7/01	1,000,000	993,982	1,000,000	N.A.	91,530	9.21%
121	9.15% Ser. C due 7/16/01	7/91	7/01	3,000,000	2,975,948	3,000,000	N.A.	278,250	9.35%
122	9.17% Ser. B due 7/17/01	7/91	7/01	1,000,000	993,732	1,000,000	N.A.	92,670	9.33%
123	9.06% Ser. C due 7/23/01	7/91	7/01	1,000,000	991,983	1,000,000	N.A.	91,840	9.26%
124	9.09% Ser. C due 7/24/01	7/91	7/01	1,000,000	991,983	1,000,000	N.A.	92,140	9.29%
125	9.10% Ser. C due 7/30/01	7/91	7/01	5,000,000	4,959,162	5,000,000	N.A.	461,200	9.30%
126	7.50% Ser. E due 8/1/01	11/92	8/01	2,000,000	1,894,328	2,000,000	N.A.	166,940	8.81%
127	8.99% Ser. C due 8/7/01	8/91	8/01	3,000,000	2,975,948	3,000,000	N.A.	273,420	9.19%
128	9.00% Ser. B due 8/8/01	8/91	8/01	2,500,000	2,484,331	2,500,000	N.A.	227,425	9.15%
129	9.00% Ser. C due 8/8/01	8/91	8/01	500,000	495,991	500,000	N.A.	45,620	9.20%
130	7.18% Ser. D due 8/15/02	8/92	8/02	3,500,000	3,478,125	3,500,000	N.A.	254,415	7.31%
131	7.20% Ser. D due 8/15/02	8/92	8/02	6,000,000	5,962,500	6,000,000	N.A.	437,340	7.33%
132	7.12% Ser. D due 8/15/02	8/92	8/02	4,000,000	3,975,000	4,000,000	N.A.	288,360	7.25%
133	7.20% Ser. D due 8/15/02	8/92	8/02	12,000,000	11,925,000	12,000,000	N.A.	874,680	7.33%
134	7.20% Ser. D due 8/15/02	8/92	8/02	6,500,000	6,459,375	6,500,000	N.A.	473,785	7.33%
135	7.20% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	N.A.	728,900	7.33%
136	7.18% Ser. D due 8/15/02	8/92	8/02	10,000,000	9,937,500	10,000,000	N.A.	726,900	7.31%

	<u>Description</u>	<u>Issue Date</u> Mo./Yr.	<u>Maturity Date</u> Mo./Yr.	<u>Principal Amount</u>	<u>Net Proceeds</u>	<u>Outstanding Per Balance Sheet</u>	<u>Yield to Maturity</u>	<u>Annual Net Cost Inc.</u> <u>Prem/Disc.</u>	<u>Total Cost %</u>
137	SECURED MEDIUM-TERM NOTES (Cont.):								
138	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	N.A.	1,471,600	7.41%
139	7.21% Ser. E due 9/9/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	733,600	7.40%
140	7.25% Ser. E due 9/9/02	9/92	9/02	20,000,000	19,849,500	20,000,000	N.A.	1,471,600	7.41%
141	7.14% Ser. E due 9/10/02	9/92	9/02	1,500,000	1,465,125	1,500,000	N.A.	112,110	7.65%
142	6.98% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	710,400	7.17%
143	6.97% Ser. E due 9/16/02	9/92	9/02	2,000,000	1,962,000	2,000,000	N.A.	144,800	7.38%
144	6.95% Ser. E due 9/16/02	9/92	9/02	10,000,000	9,912,000	10,000,000	N.A.	707,400	7.14%
145	7.00% Ser. E due 9/17/02	9/92	9/02	1,000,000	968,250	1,000,000	N.A.	74,560	7.70%
146	6.97% Ser. E due 9/23/02	9/92	9/02	1,500,000	1,465,125	1,500,000	N.A.	109,530	7.48%
147	9.00% Ser. C due 9/1/03	6/91	9/03	55,226,000	51,176,778	51,274,384	N.A.	4,628,026	9.04%
148	7.03% Ser. E due 10/15/03	10/92	10/03	5,000,000	4,033,191	5,000,000	N.A.	498,150	12.35%
149	7.39% Ser. E due 10/21/03	10/92	10/03	5,000,000	4,033,191	5,000,000	N.A.	518,950	12.87%
150	7.27% Ser. E due 10/21/03	10/92	10/03	2,000,000	1,613,276	2,000,000	N.A.	204,800	12.69%
151	7.30% Ser. E due 10/22/03	10/92	10/03	2,000,000	1,613,276	2,000,000	N.A.	205,500	12.74%
152	7.86% Ser. D due 2/16/04	2/92	2/04	2,500,000	2,330,463	2,500,000	N.A.	219,650	9.43%
153	7.79% Ser. D due 2/16/04	2/92	2/04	6,000,000	5,465,948	6,000,000	N.A.	541,140	9.90%
154	7.75% Ser. D due 2/16/04	2/92	2/04	3,000,000	2,732,975	3,000,000	N.A.	269,310	9.85%
155	7.81% Ser. D due 2/16/04	2/92	2/04	20,000,000	18,606,209	20,000,000	N.A.	1,752,000	9.42%
156	7.32% Ser. E due 9/3/04	9/92	9/04	7,500,000	7,427,625	7,500,000	N.A.	558,225	7.52%
157	7.11% Ser. E due 9/24/04	9/92	9/04	6,500,000	6,433,875	6,500,000	N.A.	470,470	7.31%
158	7.66% Ser. E due 10/22/04	11/92	10/04	5,000,000	4,734,570	5,000,000	N.A.	418,500	8.84%
159	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	N.A.	1,011,900	12.54%
160	7.30% Ser. E due 10/22/04	10/92	10/04	10,000,000	8,066,382	10,000,000	N.A.	1,011,900	12.54%
161	7.53% Ser. E due 10/26/04	10/92	10/04	750,000	604,979	750,000	N.A.	77,888	12.87%
162	7.71% Ser. E due 10/27/04	10/92	10/04	3,250,000	2,621,575	3,250,000	N.A.	344,305	13.13%
163	7.71% Ser. E due 10/27/04	10/92	10/04	3,000,000	2,419,915	3,000,000	N.A.	317,820	13.13%
164	7.60% Ser. E due 11/1/04	11/92	11/04	1,000,000	946,914	1,000,000	N.A.	83,070	8.77%
165	7.72% Ser. E due 11/2/04	11/92	11/04	1,500,000	1,420,371	1,500,000	N.A.	126,480	8.90%
166	7.36% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	N.A.	502,900	12.47%
167	7.34% Ser. E due 10/17/05	10/92	10/05	5,000,000	4,033,191	5,000,000	N.A.	501,750	12.44%
168	7.67% Ser. C due 1/10/07	1/92	1/07	5,724,000	5,341,355	5,724,000	N.A.	484,537	9.07%
169	7.43% Ser. E due 9/11/07	9/92	9/07	2,000,000	1,961,500	2,000,000	N.A.	152,960	7.80%
170	7.22% Ser. E due 9/18/07	9/92	9/07	2,500,000	2,458,250	2,500,000	N.A.	185,150	7.53%

LONG TERM DEBT (Continued)

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
171	SECURED MEDIUM-TERM NOTES (Cont.):								
172	7.27% Ser. E due 9/24/07	9/92	9/07	4,000,000	3,948,500	4,000,000	N.A.	296,560	7.51%
173	9.15% Ser. C due 8/9/11	8/91	8/11	8,000,000	7,925,861	8,000,000	N.A.	740,240	9.34%
174	8.95% Ser. C due 9/1/11	8/91	9/11	25,000,000	24,828,315	25,000,000	N.A.	2,256,250	9.09%
175	8.95% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,870,852	20,000,000	N.A.	1,804,000	9.08%
176	8.92% Ser. C due 9/1/11	8/91	9/11	20,000,000	19,814,652	20,000,000	N.A.	1,804,200	9.11%
177	8.29% Ser. C due 12/30/11	12/91	12/11	3,000,000	2,795,607	3,000,000	N.A.	270,960	9.69%
178	8.26% Ser. C due 1/10/12	1/92	1/12	1,000,000	931,901	1,000,000	N.A.	90,000	9.66%
179	8.28% Ser. C due 1/10/12	1/92	1/12	2,000,000	1,865,802	2,000,000	N.A.	180,200	9.66%
180	8.25% Ser. C due 2/1/12	1/92	2/12	3,000,000	2,795,702	3,000,000	N.A.	269,700	9.65%
181	8.53% Ser. C due 12/16/21	12/91	12/21	15,000,000	13,978,039	15,000,000	N.A.	1,380,300	9.87%
182	8.375% Ser. C due 12/31/21	12/91	12/21	5,000,000	4,659,346	5,000,000	N.A.	451,850	9.70%
183	8.26% Ser. C due 1/7/22	1/92	1/22	5,000,000	4,664,504	5,000,000	N.A.	445,250	9.55%
184	8.27% Ser. C due 1/10/22	1/92	1/22	4,000,000	3,727,603	4,000,000	N.A.	357,040	9.58%
185	8.05% Ser. E due 9/1/22	9/92	9/22	15,000,000	14,862,000	15,000,000	N.A.	1,219,800	8.21%
186	8.11% Ser. E due 9/9/22	9/92	9/22	12,000,000	11,884,500	12,000,000	N.A.	983,640	8.28%
187	8.07% Ser. E due 9/9/22	9/92	9/22	8,000,000	7,914,500	8,000,000	N.A.	653,280	8.25%
188	8.12% Ser. E due 9/9/22	9/92	9/22	50,000,000	49,599,500	50,000,000	N.A.	4,096,000	8.26%
189	8.05% Ser. E due 9/14/22	9/92	9/22	10,000,000	9,899,500	10,000,000	N.A.	814,000	8.22%
190	8.08% Ser. E due 10/14/22	10/92	10/22	26,000,000	20,390,094	26,000,000	N.A.	2,715,700	13.32%
191	8.08% Ser. E due 10/14/22	10/92	10/22	25,000,000	19,584,706	25,000,000	N.A.	2,614,250	13.35%
192									
193	Total Secured Med-Term Notes			1,407,000,000	1,360,983,350	1,403,048,384		121,150,466	8.90%
194									
195	POLL. CTRL. OBLIGATIONS - SECURED BY PLEDGED FIRST MORTGAGE BONDS:								
196	6-1/8% Series due 2/04 Emery	2/74	2/04	14,000,000	13,283,631	13,540,000	N.A.	848,417	6.39%
197	6-1/8% Series due 2/04 Carbon	2/74	2/04	11,000,000	9,482,001	9,665,000	N.A.	605,609	6.39%
198	6-1/8% Series due 2/04 Lincln	2/74	2/04	16,000,000	15,167,276	15,460,000	N.A.	968,723	6.39%
199	6-3/8% Series due 11/06 Emery	11/76	11/06	50,000,000	48,728,350	50,000,000	N.A.	3,285,000	6.74%
200	5.90% Series due 4/08 Emery	4/78	4/08	42,000,000	41,224,321	42,000,000	N.A.	2,534,280	6.15%
201	10.70% Series due 9/14 Emery	9/84	9/14	16,750,000	15,736,753	16,750,000	N.A.	1,912,180	12.15%
202	8-1/4% Series due 6/17 Emery	6/87	6/17	46,500,000	45,117,498	46,500,000	N.A.	3,964,590	8.79%
203	8-5/8% Series due 6/17 Emery	6/87	6/17	16,400,000	15,875,079	16,400,000	N.A.	1,465,012	9.23%
204	8-5/8% Series due 6/17 Lincln	6/87	6/17	8,300,000	8,034,339	8,300,000	N.A.	741,439	9.23%

Sch. 24	LONG TERM DEBT (Continued)									
	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds (Cont.):	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %	
205	POLL. CTRL. OBLIGATIONS – SECURED BY PLEDGED FIRST MORTGAGE BONDS									
206	6.550% Series due 5/93 Moffat	5/78	5/93	1,560,000	1,558,131	1,560,000	N.A.	110,776	7.11%	
207	6.600% Series due 5/94 Moffat	5/78	5/94	1,660,000	1,658,011	1,660,000	N.A.	117,694	7.10%	
208	6.650% Series due 5/95 Moffat	5/78	5/95	1,770,000	1,767,880	1,770,000	N.A.	126,024	7.13%	
209	6.700% Series due 5/96 Moffat	5/78	5/96	1,890,000	1,887,736	1,890,000	N.A.	135,324	7.17%	
210	6.700% Series due 5/97 Moffat	5/78	5/97	2,015,000	2,012,586	2,015,000	N.A.	144,153	7.16%	
211	6.700% Series due 5/98 Moffat	5/78	5/98	2,150,000	2,147,424	2,150,000	N.A.	153,725	7.16%	
212	6.875% Series due 5/08 Moffat	5/78	5/08	35,030,000	34,988,037	35,030,000	N.A.	2,561,394	7.32%	
213	6-3/8% Series due 1/1/07	1/77	1/07	17,000,000	7,974,431	8,190,000	N.A.	538,656	6.75%	
214										
215	Total Poll Ctrl Oblg Sec by FMB			284,025,000	266,643,484	272,880,000		20,212,996	7.58%	
216										
217	FIXED RATE POLL CTRL REVENUE BONDS:									
218	6% Series due 10/1/03	10/73	10/03	25,000,000	20,964,726	21,260,000	N.A.	1,297,073	6.19%	
219										
220	Total Fixed Rate PCRB's			25,000,000	20,964,726	21,260,000		1,297,073		
221										
222	VARIABLE RATE POLL CTRL REVENUE BONDS:									
223	Var. Rate Emery Co. 1991	5/91	7/15	45,000,000	52,440,000	45,000,000	N.A.	4,011,750	7.65%	
224	Var. Rate Lincoln Co. 1991	1/91	1/16	45,000,000	52,440,000	45,000,000	N.A.	4,011,750	7.65%	
225	Var. Rate Forsyth 1988	1/88	1/18	45,000,000	44,619,802	45,000,000	N.A.	3,858,750	8.65%	
226	Var. Rate Sweetwater A	1/88	1/17	50,000,000	49,577,557	50,000,000	N.A.	2,113,000	4.26%	
227	Var. Rate Gillette (Wyodak)	1/88	1/18	41,200,000	40,972,358	41,200,000	N.A.	4,985,200	12.17%	
228	Var. Rate Sweetwater 88B/Converse	1/88	1/14	28,500,000	27,429,996	28,500,000	N.A.	2,431,905	8.87%	
229	Var. Rate Sweetwater C	12/84	12/14	15,000,000	14,772,113	15,000,000	N.A.	1,252,800	8.48%	
230	Var. Rate Forsyth 1986	12/86	12/16	8,500,000	8,195,176	8,500,000	N.A.	370,940	4.53%	
231	Var. Rate Sweetwater 1990A	7/90	7/19	21,100,000	20,889,000	21,100,000	N.A.	960,894	4.60%	
232	Var. Rate Sweetwater 1990A	7/90	7/15	70,000,000	68,965,857	70,000,000	N.A.	6,652,488	9.65%	
233	Var. Rate Sweetwater 1992A	9/92	4/05	9,335,000	9,053,325	9,335,000	N.A.	464,883	5.13%	
234	Var. Rate Converse 1992	9/92	7/06	22,485,000	21,968,372	22,485,000	N.A.	1,068,487	4.86%	
235	Var. Rate Sweetwater 1992B	9/92	12/05	6,305,000	6,172,572	6,305,000	N.A.	300,181	4.86%	
236										
237	Total Variable Rate PCRB's			407,425,000	417,496,128	407,425,000		32,483,028	7.78%	
238										

	<u>Description</u>	<u>Issue Date</u> Mo./Yr.	<u>Maturity Date</u> Mo./Yr.	<u>Principal Amount</u>	<u>Net Proceeds</u>	<u>Outstanding Per Balance Sheet</u>	<u>Yield to Maturity</u>	<u>Annual Net Cost Inc. Prem/Disc.</u>	<u>Total Cost %</u>
239	CONSTR. FUND ON DEPOSIT W/ TRUSTEE:								
240	Lincoln County Constr. Fund			(8,134,830)		0			
241	Sweetwater County Constr. Fund			(21,100,000)		(884,875)			
242									
243	Total Construction Funds (Acct 221.5)			(29,234,830)	0	(884,875)		0	
244									
245									
246	TOTAL BONDS (Acct. 221)			3,171,107,170	2,974,117,161	3,017,508,509		247,502,086	8.32%
247									
248									
249									
250									
251									
252									
253									
254									
255									
256									
257									
258									
259									
260									
261									
262									
263									
264									
265									
266									
267									
268									
269									
270									
271									
272									

Sch. 25										
PREFERRED STOCK										
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value(a)	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	5% cumulative preferred	(b)	126,533	100.00	110.00	12,555,021	5.00%	12,653,300	632,665	5.04%
2	Serial preferred, cumulative:									
3	4.52% Series	11/55	2,065	100.00	103.50	196,824	4.52%	206,500	9,334	4.74%
4	7.00% Series	(c)	18,060	100.00	None	1,806,000	7.00%	1,806,000	126,420	7.00%
5	6.00% Series	(c)	5,932	100.00	None	593,200	6.00%	593,200	35,592	6.00%
6	5.00% Series	(c)	42,000	100.00	100.00	4,200,000	5.00%	4,200,000	210,000	5.00%
7	5.40% Series	(c)	65,960	100.00	101.00	6,596,000	5.40%	6,596,000	356,184	5.40%
8	4.72% Series	8/63	69,890	100.00	103.50	6,958,651	4.72%	6,989,000	329,881	4.74%
9	4.56% Series	2/65	84,592	100.00	102.34	8,410,129	4.56%	8,459,200	385,740	4.59%
10	8.92% Series	11/69	69,375	100.00	102.37	6,923,997	8.92%	6,937,500	618,825	8.94%
11	9.08% Series	6/71	164,893	100.00	104.02	16,440,752	9.08%	16,489,300	1,497,228	9.11%
12	7.96% Series	10/72	135,176	100.00	103.39	13,492,533	7.96%	13,517,600	1,076,001	7.97%
13										
14	No par serial preferred cumulative:									
15	\$2.13 Series	5/77	666,210	25.00	26.07	15,992,249	8.52%	16,655,250	1,419,027	8.87%
16	\$7.12 Series	3/87	440,000	100.00	107.12	43,510,042	7.12%	44,000,000	3,132,800	7.20%
17	\$1.28 Series	9/60	381,220	25.00	26.35	9,530,500	5.12%	9,530,500	487,962	5.12%
18	\$1.18 Series	5/62	420,116	25.00	26.15	10,502,900	4.72%	10,502,900	495,737	4.72%
19	\$1.16 Series	8/64	193,102	25.00	26.11	4,827,550	4.64%	4,827,550	223,998	4.64%
20	\$1.76 Series	3/68	393,868	25.00	25.96	9,846,700	7.04%	9,846,700	693,208	7.04%
21	\$1.98 Series – 1971	3/71	501,998	25.00	26.21	12,549,950	7.92%	12,549,950	993,956	7.92%
22	\$7.70 Series	8/91	1,000,000	100.00	100.00	99,088,457	7.70%	100,000,000	7,700,000	7.77%
23	\$1.98 Series – 1992	5/92	5,000,000	25.00	N. A.	120,787,500	7.92%	125,000,000	9,900,000	8.20%
24	\$7.48 Series	6/92	750,000	100.00	N. A.	73,684,265	7.48%	75,000,000	5,610,000	7.61%
25	DARTS Series A	3/87	500	100,000.00	100,000.00	49,167,311	Variable	50,000,000	2,175,000	4.42%
26	DARTS Series B	3/87	500	100,000.00	100,000.00	49,167,311	Variable	50,000,000	2,275,000	4.63%
27	MAPS Series C	10/90	500	No Par	100,000.00	49,241,397	Variable	50,000,000	2,375,000	4.82%
28										
29										
30										
31										
32										
33	TOTAL		10,532,490			626,069,239		636,360,450	42,759,557	6.83%

- (a) Par or Stated Value
- (b) Replaced preferred stock issues sold in the 1920's and 1930's.
- (c) Replaced an issue of The California Oregon Power Company as a result of merger with Pacific Power.

Preferred stock

	Avg. Number of Shares Outstanding	Book Value Per Share	Earnings, Per Share	Dividends Per Share	Retention Ratio	Market Price High	Low	Price/ Earnings Ratio
1								
2								
3								
4	January	262,453,910	13.87	0.15		25.250	22.250	
5								
6	February	263,010,164	13.59	0.09		23.000	21.250	
7								
8	March	263,593,895	12.66	(0.96)	-52.08%	22.000	21.000	(7.5)
9								
10	April	263,893,355	12.73	0.06		23.375	21.250	
11								
12	May	264,388,024	12.43	0.08		22.750	21.375	
13								
14	June	266,206,660	12.60	0.08	-75.00%	23.000	22.000	25.6
15								
16	July	267,642,670	12.76	0.13		23.625	22.250	
17								
18	August	268,318,392	12.49	0.12		23.125	22.250	
19								
20	September	268,846,835	12.52	(0.02)	-67.39%	23.000	22.125	24.5
21								
22	October	269,399,257	12.57	0.06		23.125	21.875	
23								
24	November	269,907,315	12.29	0.11		22.250	18.125	
25								
26	December	270,469,899	11.00	(1.32)	-33.48%	20.875	19.250	(4.4)
27								
28								
29								
30								
31								
32								
33	TOTAL Year End	266,526,853	11.00	(1.42)	-107.75%	19.750		(13.9)

MONTANA EARNED RATE OF RETURN

	Description	Last Year	This Year	% Change
	Rate Base (Year-end Average)			
1				
2	101 Plant in Service		144,430,578	N / A
3	108 (Less) Accumulated Depreciation		(43,676,896)	N / A
4	NET Plant in Service	0	100,753,682	N / A
5				
6	<u>Additions</u>			
7	154, 156 Materials & Supplies		3,031,886	N / A
8	165 Prepayments		641,648	N / A
9	Other Additions		4,206,719	N / A
10	TOTAL Additions	0	7,880,253	N / A
11				
12	<u>Deductions</u>			
13	190 Accumulated Deferred Income Taxes		(4,869,626)	N / A
14	252 Customer Advances for Construction		(50,417)	N / A
15	255 Accumulated Def. Investment Tax Credits		(732,605)	N / A
16	Other Deductions		(172,124)	N / A
17	TOTAL Deductions	0	(5,824,772)	N / A
18	TOTAL Rate Base	0	102,809,163	N / A
19				
20	Net Earnings		7,574,170	N / A
21				
22	Rate of Return on Average Rate Base		7.37%	N / A
23				
24	Rate of Return on Average Equity		6.24%	N / A
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28	Commission Ordered / Allowed Ratemaking Adjustments			
29	- Malin Midpoint Adj.		31,000	N / A
30	- Unbilled Revenue Adj.		100,138	N / A
31	- Advertising Expense Adj.		(2,095)	N / A
32	- Present Rates Adj.		22,583	N / A
33	- Weather Normalization Adj.		536,125	N / A
34	- Bridger Coal Adj.		13,167	N / A
35	- Production Cost Study Adj.		705,090	N / A
36	- Interest Expense Adj.		287,394	N / A
37				
38				
39	Other Company Ratemaking Adjustments			
40	- Other Adjustments		333,702	N / A
41				
42				
43				
44				
45	Adjusted Net Earnings		9,601,274	N / A
46				
47	- Associated Rate Base Adjustments for the above		4,431,242	N / A
48	Reference Ratemaking Adjustments			
49	Adjusted Rate Base		107,240,405	N / A
50	Adjusted Rate of Return on Average Rate Base		8.95%	N / A
51				
52	Adjusted Rate of Return on Average Equity		10.75%	N / A

PACIFICORP
State of Montana - Electric Utility
Schedule 28 Detail for Other Rate Base Additions / Deductions
Twelve Months Ended December 31, 1992

1 Rate Base:

2 Plant Held for Future Use	94,183
3 Misc Deferred Debits	1,909,370
4 Electric Plant Acquisition Adj	352,644
5 Nuclear Fuel	15,738
6 Working Capital (1)	1,358,042
7 Weatherization Loans	125,344
8 Deferred Trojan Decommissioning	351,398
9 Total Other Additions	<u>4,206,719</u>

10

11 Deductions:

12 Accum Prov Trojan Decommissioning	(172,124)
13 Total Other Deductions	<u>(172,124)</u>

(1) The Company does not have a specific Commission order authorizing the inclusion of cash working capital in rate base. However, cash working capital has been allowed in Company's previously authorized results (reference rate filings for Docket No. 87.12.80, Order No. 5326 and for Docket No. 89.6.17, Order No. 5432).

PAGE 01

MISCELLANEOUS DEFERRED DEBITS
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

RELIANCE

DESCRIPTION	TOTAL COMPANY	ALOC BASIS	CALIF	OREGON	WASH	ID-PFL	MONTANA	WY-PFL	UTAH	ID-UFL	WY-UFL	FERC
000000032 JB OIL SEEPAGE	21	SG		7	2			3	6		1	
000000757 WUK ASH DISPOSAL	89	SG	2	29	6	1	2	13	27	4	4	
000000473 #2 TURBINE OUTAGE	160	INFFSP	5	77	22	1	4	35	13	2	2	
0000006797 SWIFT-SPEELEYAI	16	IGF	1	8	2			4				
0000006334 COMPETITIVE BID	127	WA	3	38	10	1	2	15	45	7	5	
0000007190 REMOVAL OF UST	11	SG		4	1			2	3			
0000007198 COLORADO UTE M&A		INFFSU										
0000007391 HUNTER #2 STM LN		SE										
0000007651 FUEL RESOURCES		VARIOUS										
0000007860 HF ENERGY EFFIC		OK										
0000009260 COMPETITIVE BID	3	INFFP		1				1				
0000007393 XFORMER FAILURE	230	SG	5	75	21	1	4	34	70	10	10	
0000008900 ESD ASH MGT ANAL	6	SG		2				1	2			
0000007725 ESD ASSESSMENT	8	SG		1	1			1	2			
0000007736 ESD ASSESSMENT	-73	SE	-1	-22	-6		-1	-12	-23	-3	-4	
000010143 L#2 FULL SHAFT	2	SG		1	3			4	1			
000010332 MFC'S WHITE PAPER	18	INFFSP	1	9	2			4	2	1	1	
000010373 L#50 R/R 2A CRUSH	25	SG	1	8	2			4	7	1	1	
000010559 GLENN CANYON-NAVAH	8	INFFSU		3	1			1	3			
000010789 CARRION 2-3 MILL FI	10	SG										
000011014 NAUGHTON FAN REBLD	3	SG		1					1			
000011473 CARRION DIESEL LINE	3	SG										
000011524 HUNTER 303 TURBINE	-18	INFFSU	-1	-9	-3			-4	-2	1	1	
000011649 HUNTER 301 COAL MI	76	INFFSP	2	36	10	1	2	16	6			
000012245 HUNTER WAGHOUSE RE	103	CA	103	-1					-1			
000022182 UJ INSURANCE LOSS	-2	SG	14	221	63	4	11	99	204	29	28	
000031543 ALTURAC LEGAL	673	SG	4	39	11	1	2	16	48	7	6	
000045778 WUK ASH DISPOSAL	133	SG										
000046889 AMBIENT AIR MONITO	5	SG	10	113	31	2	6	46	137	21	16	
000055118 HIGHLAND BOY CLEAN	383	SG	77	852	230	18	47	344	1,029	155	123	
000055119 EMWIRGN REG FEES	2,878	SG	5	52	14	1	3	21	63	9	7	
000055121 LG STORAGE TANK	176	SG	10	115	31	1	6	47	139	21	17	
000055313 HAZARDOUS WASTE	390	SG	3	29	8	1	2	12	35	5	4	
000055537 COAL CREEK PCB	97	SG	19	207	56	4	12	84	251	38	30	
000055538 FORT EQUIP PCB	701	SG		3	1			1	4	1		
000057119 UST TIGHTNESS TEST	11	SG		2	1			1	3			
000057122 BARBER TAR	8	SG										
000057123 UTAH METAL WORKS	147	SG	4	43	12	1	2	18	52	8	6	
000057124 PROJECT FENTA	752	SG	16	246	70	4	13	111	228	32	32	
000057125 BOKS	1	SG										
000057130 EROTEK SETTLEMENT	3	SG		1	-2			-3	1	-1	-1	
000057141 VISIBILITY STUDIES	-21	SG	-14	-7	-63	-4	-11	-99	-6	-29	-28	
000057145 HIGHLAND BOY SHEL	-675	SG		-221					-204			
000100445 HIGHLAND BOY SHEL	-1	SG										
000103172 HUNTER #3 BOILER	3	SG		1					1			
000102876 NTO CONST COST	-21	SG		-7					-6			
000005032 JB OIL SEEPAGE	-675	SG	-14	-221	-63	-4	-11	-99	-204	-29	-28	
000046889 AMBIENT AIR MONITO	-1	SG										
000051118 HIGHLAND BOY CLEAN	-5	SG		-2				-1	-2			
000055119 ENVIRON REG FEES		SG										

IATD RT12
 04/21/93
 62 MOLES

PAGE 03

MISCELLANEOUS DEFERRED BENEFITS
 ALLOCATED - IN THOUSANDS
 PERIOD ENDING 12/92

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-PFL	MONTANA	WY-PFL	UTAH	ID-UFL	WY-UFL	FERC
18671 000057125 HORS		SO										
18671 000057126 ERSICK SETTLEMENT	122	SO	3	36	10	1	2	15	44	7	5	
18671 000057141 VISIBILITY STUDIES	532	SG	11	174	49	3	9	78	161	23	22	1
18671 000100445 HIGHLAND BOY SHEL	1	SO										
TOTAL HISE DEFERRED	63,311		1,316	18,411	6,488	336	1,316	13,092	16,209	2,386	3,667	89

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

DEFD SPT1
04/21/93
92 NOTES

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID-FTL	MONTANA	WY-FFL	UTAH	ID-UFL	WY-UFL	FERC
18672 000035980 SUPER GOOD CENT 88	57	OR										
18672 000035989 SUPER GOOD CENT 89	843	OR		57								
18672 000035990 SUPER GOOD CENT 90	3,307	OR		843								
18672 000035991 SUPER GOOD CENT 91	3,732	OR		3,307								
18672 000035992 SUPER GOOD CENT 92	5,190	OR		3,732								
18672 000036000 SUPER GOOD CENT 89	9	WA		5,190								
18672 000036001 SUPER GOOD CENT 88	24	MT										
18672 000036002 SUPER GOOD CENT 89	24	MT										
18672 000036003 SUPER GOOD CENT 90	58	MT										
18672 000036004 SUPER GOOD CENT 91	113	MT										
18672 000036005 SUPER GOOD CENT 92	146	MT										
18672 000036006 SUPER GOOD CENT 91	60	UT										
18672 000036007 SUPER GOOD CENT 92	109	UT										
18672 000036008 SUPER GOOD CENT 92	89	WY										
18672 000036009 SUPER GOOD CENT 92	18	MT										
18672 000036010 SUPER GOOD CENT 92	1	MT										
18672 000036011 SUPER GOOD CENT 92	4	MT										
18672 000036012 SUPER GOOD CENT 92	3	MT										
18672 000036013 SUPER GOOD CENT 92	3	MT										
18672 000036014 SUPER GOOD CENT 92	6	MT										
18672 000036015 SUPER GOOD CENT 92	36	MT										
18672 000036016 SUPER GOOD CENT 92	29	MT										
18672 000036017 SUPER GOOD CENT 92	6	MT										
18672 000036018 SUPER GOOD CENT 92	4	MT										
18672 000036019 SUPER GOOD CENT 92	6	MT										
18672 000036020 SUPER GOOD CENT 92	46	MT										
18672 000036021 SUPER GOOD CENT 92	49	MT										
18672 000036022 SUPER GOOD CENT 92	1	MT										
18672 000036023 SUPER GOOD CENT 92	12	MT										
18672 000036024 SUPER GOOD CENT 92	10	MT										
18672 000036025 SUPER GOOD CENT 92	1	MT										
18672 000036026 SUPER GOOD CENT 92	2	MT										
18672 000036027 SUPER GOOD CENT 92	11	MT										
18672 000036028 SUPER GOOD CENT 92	2	MT										
18672 000036029 SUPER GOOD CENT 92	42	MT										
18672 000036030 SUPER GOOD CENT 92	2	MT										
18672 000036031 SUPER GOOD CENT 92	1	MT										
18672 000036032 SUPER GOOD CENT 92	30	WY										
18672 000036033 SUPER GOOD CENT 92	9	WY										
18672 000036034 SUPER GOOD CENT 92	2	WY										
18672 000036035 SUPER GOOD CENT 92	5	WY										
18672 000036036 SUPER GOOD CENT 92	2	WY										
18672 000036037 SUPER GOOD CENT 92	5	CA										
18672 000036038 SUPER GOOD CENT 92	9	CA										
18672 000036039 SUPER GOOD CENT 92	14	CA										
18672 000036040 SUPER GOOD CENT 92	14	CA										
18672 000036041 SUPER GOOD CENT 92	12	CA										
18672 000036042 SUPER GOOD CENT 92	12	CA										
18672 000036043 SUPER GOOD CENT 92	12	CA										
18672 000036044 SUPER GOOD CENT 92	12	CA										
18672 000036045 SUPER GOOD CENT 92	12	CA										
18672 000036046 SUPER GOOD CENT 92	12	CA										
18672 000036047 SUPER GOOD CENT 92	12	CA										
18672 000036048 SUPER GOOD CENT 92	12	CA										
18672 000036049 SUPER GOOD CENT 92	12	CA										
18672 000036050 SUPER GOOD CENT 92	12	CA										
18672 000036051 SUPER GOOD CENT 92	12	CA										
18672 000036052 SUPER GOOD CENT 92	12	CA										
18672 000036053 SUPER GOOD CENT 92	12	CA										
18672 000036054 SUPER GOOD CENT 92	12	CA										
18672 000036055 SUPER GOOD CENT 92	12	CA										
18672 000036056 SUPER GOOD CENT 92	12	CA										
18672 000036057 SUPER GOOD CENT 92	12	CA										
18672 000036058 SUPER GOOD CENT 92	12	CA										
18672 000036059 SUPER GOOD CENT 92	12	CA										
18672 000036060 SUPER GOOD CENT 92	12	CA										
18672 000036061 SUPER GOOD CENT 92	12	CA										
18672 000036062 SUPER GOOD CENT 92	12	CA										
18672 000036063 SUPER GOOD CENT 92	12	CA										
18672 000036064 SUPER GOOD CENT 92	12	CA										
18672 000036065 SUPER GOOD CENT 92	12	CA										
18672 000036066 SUPER GOOD CENT 92	12	CA										
18672 000036067 SUPER GOOD CENT 92	12	CA										
18672 000036068 SUPER GOOD CENT 92	12	CA										
18672 000036069 SUPER GOOD CENT 92	12	CA										
18672 000036070 SUPER GOOD CENT 92	12	CA										
18672 000036071 SUPER GOOD CENT 92	12	CA										
18672 000036072 SUPER GOOD CENT 92	12	CA										
18672 000036073 SUPER GOOD CENT 92	12	CA										
18672 000036074 SUPER GOOD CENT 92	12	CA										
18672 000036075 SUPER GOOD CENT 92	12	CA										
18672 000036076 SUPER GOOD CENT 92	12	CA										
18672 000036077 SUPER GOOD CENT 92	12	CA										
18672 000036078 SUPER GOOD CENT 92	12	CA										
18672 000036079 SUPER GOOD CENT 92	12	CA										
18672 000036080 SUPER GOOD CENT 92	12	CA										
18672 000036081 SUPER GOOD CENT 92	12	CA										
18672 000036082 SUPER GOOD CENT 92	12	CA										
18672 000036083 SUPER GOOD CENT 92	12	CA										
18672 000036084 SUPER GOOD CENT 92	12	CA										
18672 000036085 SUPER GOOD CENT 92	12	CA										
18672 000036086 SUPER GOOD CENT 92	12	CA										
18672 000036087 SUPER GOOD CENT 92	12	CA										
18672 000036088 SUPER GOOD CENT 92	12	CA										
18672 000036089 SUPER GOOD CENT 92	12	CA										
18672 000036090 SUPER GOOD CENT 92	12	CA										
18672 000036091 SUPER GOOD CENT 92	12	CA										
18672 000036092 SUPER GOOD CENT 92	12	CA										
18672 000036093 SUPER GOOD CENT 92	12	CA										
18672 000036094 SUPER GOOD CENT 92	12	CA										
18672 000036095 SUPER GOOD CENT 92	12	CA										
18672 000036096 SUPER GOOD CENT 92	12	CA										
18672 000036097 SUPER GOOD CENT 92	12	CA										
18672 000036098 SUPER GOOD CENT 92	12	CA										
18672 000036099 SUPER GOOD CENT 92	12	CA										
18672 000036100 SUPER GOOD CENT 92	12	CA										
18672 000036101 SUPER GOOD CENT 92	12	CA										
18672 000036102 SUPER GOOD CENT 92	12	CA										
18672 000036103 SUPER GOOD CENT 92	12	CA										
18672 000036104 SUPER GOOD CENT 92	12	CA										
18672 000036105 SUPER GOOD CENT 92	12	CA										
18672 000036106 SUPER GOOD CENT 92	12	CA										
18672 000036107 SUPER GOOD CENT 92	12	CA										
18672 000036108 SUPER GOOD CENT 92	12	CA										
18672 000036109 SUPER GOOD CENT 92	12	CA										
18672 000036110 SUPER GOOD CENT 92	12	CA										
18672 000036111 SUPER GOOD CENT 92	12	CA										
18672 000036112 SUPER GOOD CENT 92	12	CA										
18672 000036113 SUPER GOOD CENT 92	12	CA										
18672 000036114 SUPER GOOD CENT 92	12	CA										
18672 000036115 SUPER GOOD CENT 92	12	CA										
18672 000036116 SUPER GOOD CENT 92	12	CA										
18672 000036117 SUPER GOOD CENT 92	12	CA										
18672 000036118 SUPER GOOD CENT 92	12	CA										
18672 000036119 SUPER GOOD CENT 92	12	CA										
18672 000036120 SUPER GOOD CENT 92	12	CA										
18672 000036121 SUPER GOOD CENT 92	12	CA										
18672 000036122 SUPER GOOD CENT 92	12	CA										
18672 000036123 SUPER GOOD CENT 92	12	CA										
18672 000036124 SUPER GOOD CENT 92	12	CA										
18672 000036125 SUPER GOOD CENT 92	12	CA										
18672 000036126 SUPER GOOD CENT 92	12	CA										
18672 000036127 SUPER GOOD CENT 92	12	CA										
18672 000036128 SUPER GOOD CENT 92	12	CA										
18672 000036129 SUPER GOOD CENT 92	12	CA										
18672 000036130 SUPER GOOD CENT 92	12	CA										
18672 000036131 SUPER GOOD CENT 92	12	CA										
18672 000036132 SUPER GOOD CENT 92	12	CA										
18672 000036133 SUPER GOOD CENT 92	12	CA										
18672 000036134 SUPER GOOD CENT 92	12	CA										
18672 000036135 SUPER GOOD CENT 92	12	CA										
18672 000036136 SUPER GOOD CENT 92												

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/92

MEMO EFF1
04/21/93
NOTES

DESCRIPTION	TOTAL COMPANY	ALLOC BASIS	CALIF	OREGON	WASH	ID FFL	MONTANA	WY-FFL	UTAH	ID-FFL	WY-FFL	FERC
185972 000030041 LOAD MANAGE FROG91	438	UT							438			
185972 000030191 SUPERFUND	132	SD							132			
185972 000030192 INFERRIAL FINANSW	40	UT							14		2	
185972 000030291 SUPERFUND	54	SD			3			5	54			
185972 000030292 CORN BUILDING	2	UT	1	12					1			
185972 000030391 SUPERFUND	70	SD							70			
185972 000030392 LOW INCOME	81	UT							81			
185972 000030492 RFT ACQUISITION	1	UT							1			
185972 000030792 TECHNOLOGY MONITOR	471	UT							471			
185972 000030791 ENERGY FINANSWER91	11	UT							11			
185972 000030792 ENERGY FINANSWER92	159	UT							159			
185972 000030792 EFF SHOWERHEADS 92	29	UT							29			
185972 000030892 FINANSWER 12000 92	28	UT							28			
185972 000030892 WHOLESALE PURCH 92	14	UT							14			
185972 000030892 HOME COMFORT 92		UT										
185972 000030992 ESC LOANS GAML 92		UT										
185972 000030992 REFRIGERATION 92		IDF										
185972 000030991 WEATHER OX ID 91		IDF										
185972 000030992 WEATHER OX ID 92		IDF										
185972 000031090 ENERGY EXCL ID 90	15	IDF								15		
185972 000031191 LOW INCOME ID 91	11	IDF								11		
185972 000031192 LOW INCOME ID 92	15	IDF								15		
185972 000031192 LOW INCOME ID 89	2	IDF								2		
185972 000032090 WEATHER RES ID 90	46	IDF								46		
185972 000032091 WEATHER RES ID 91	80	IDF								80		
185972 000032091 CASH KEBATE ID 91	67	IDF								67		
185972 000032092 CASH KEBATE ID 92	13	IDF								13		
185972 000032092 SUPER GOOD CENT 88	45	IDF								45		
185972 000032189 SUPER GOOD CENT 89	66	IDF								66		
185972 000032190 SUPER GOOD CENT 90	129	IDF								129		
185972 000032191 SUPER GOOD CENT 91	198	IDF								198		
185972 000032192 SUPER GOOD CENT 92	134	IDF								134		
185972 000032390 SUPER GOOD CENT 90	222	IDF								222		
185972 000032391 SUPER GOOD CENT 91	399	IDF								399		
185972 000032392 SUPER GOOD CENT 92		IDF										
185972 000032791 TECH MONITOR ID 91	1	WYU										
185972 000032792 TECH MONITOR ID 92		IDF										
185972 000032791 HASSLETREE EF ID91	13	IDF								13		
185972 000032792 HASSLETREE EF ID92	2	IDF								2		
185972 000032792 HASSLETREE EF ID91	49	IDF								49		
185972 000032791 ENERGY FINANS ID91	2	IDF								2		
185972 000032892 FINANSWER 12000 92	2	IDF								2		
185972 000032892 WHOLESALE PURCH 92	1	IDF								1		
185972 000032892 HOME COMFORT 92	28	IDF								28		
185972 000032892 ESC LOANS GAML 92	1	IDF								1		
185972 000032892 REFRIGERATION 92		IDF										
185972 000032892 CASH GRANT ID 92	872	IDF								872		
185972 000032892 CASH GRANT ID 90	6	IDF								6		
185972 000032891 LOW INCOME ID 91	20	IDF								20		
185972 000032892 LOW INCOME ID 92	35	IDF								35		

134
222
399

872
6
20
35

MISCELLANEOUS DEFERRED MERITS
ALLOCATED IN THOUSANDS
PERIOD ENDING 12/91

REFD RPT2
04/21/93
92 NOTEC

REGISTRATION	TOTAL COMPANY	ALOC BASIS	CALIF	OREGON	WASH	ID-PFL	MONTANA	WY-PFL	UTAH	ID-UFL	WY-UFL	PERC
18671 000055517 COAL CREEK PCB	84	SO	2	25	7	1	1	10	30	5	5	4
18671 000055519 FORT EQUIP PCB	95	SO	3	26	8	1	2	11	34	5	5	4
18671 000057123 KARNER TAR	88	SO	2	26	7	1	1	10	31	5	5	4
18671 000057123 UTAH METAL WORKS	6	SO		2				1	2			
18671 000057125 RONG		SO	1	16	4		1	6	19	3	3	2
18671 000057130 ENJOIEK SETTLEMENT	53	SO	8	131	37	2	7	59	121	17	17	1
18671 000057141 VIGILANT STUDIES	400	SG										
18671 000100445 HIGHLAND BOY SHEL	1	SO										
TOTAL MICE REFERENCE	72,857		1,446	20,329	7,012	369	1,467	15,731	18,534	2,717	5,144	109

DEFERRED WEATHERIZATION
ALLOCATED - IN THOUSANDS
PERIOD ENDING 12/91

DEFD RPT1
04/21/93
72 NOTES

DESCRIPTION	TOTAL COMPANY	ALOC BASIS	CALIF	OREGON	WASH	ID-PTL	MONTANA	WY-FFL	UTAH	ID-UFL	WY-UFL	PERC
1861 000000036 CUMM FRESBURGH	225	OR		225								
1861 000000037 HOME COMFORT	127	CA		127								
1861 000000039 ENERGY FINANSWER	144	IF		144								
1861 000000056 WHELESLE PURCH	211	SG		211								
1861 000000077 ENERGY FINANSWER	8	UT		8								
1861 000000085 LOW INCOME	36	UT		36								
1861 000010384 ZERO INTEREST-OR	38	OR		38								
1861 000010529 6% INTEREST -OR	49	OR		49								
1861 000010573 ZERO INTEREST-WA	240	WA		240								
1861 000010594 ZERO INTEREST-MT	259	MT		259								
1861 000010621 ZERO INTEREST-ID	339	IF		339								
1861 000021573 LOW INCOME	422	CA		422								
1861 000055109 FROG ARIKIN	301	CA		301								
1861 000057022 M'SIGN ADVANTAGE	476	OR		476								
1861 000057024 INDUSTRIAL PARTNER	11	OR		11								
1861 000057025 LOW INCOME	1	OR		1								
1861 000057026 FANFAC HOUSING	337	OR		337								
1861 000057165 LOW INCOME	16	CA		16								
1861 000057221 ENERGY EXCELLENCE	59	IF		59								
1861 000057223 ENERGY EXCELLENCE	409	MT		409								
1861 000057249 SUPER GOOD CENTS	520	OR		520								
1861 000057250 SUPER GOOD CENTS	10	IF		10								
1861 000057251 SUPER GOOD CENTS	35	MT		35								
1861 000057252 SUPER GOOD CENTS	179	IF		179								
1861 000057253 LOW INCOME	1	IF		1								
1861 000057254 CASH GRANT-UFL	168	IF		168								
1861 000066210 FAC ENVIRONMENT	530	OR		530								
1861 000066211 HOME COMFORT	1,034	OR		1,034								
1868 000000002 WEATHERIZATION	135	IF		135								
1868 000000040 WEATHERIZATION	306	UT		306								
1869 000000040 WEATHERIZATION	16	UT		16								
18692 000010082 WEATHER OX OR 82	370	OR		370								
18692 000010083 WEATHER OX OR 83	2,327	OR		2,327								
18692 000010084 WEATHER OX OR 84	9	OR		9								
18692 000010085 WEATHER OX OR 85	24	OR		24								
18692 000010086 WEATHER OX OR 86	212	OR		212								
18692 000010087 WEATHER OX OR 87	10	OR		10								
18692 000010088 WEATHER OX OR 88	1,438	OR		1,438								
18692 000010089 WEATHER OX OR 89	102	OR		102								
18692 000010090 WEATHER OX OR 90		OR										

	Description	Amount
1		
2	<u>Plant (Intrastate Only)</u>	
3		
4	101 Plant in Service	294,660,402
5	107 Construction Work in Progress	2,475,290
6	114 Plant Acquisition Adjustments	0
7	105 Plant Held for Future Use	0
8	154, 156 Materials & Supplies	2,069,456
9	(Less):	
10	108, 111 Depreciation & Amortization Reserves	(71,261,085)
11	252 Contributions in Aid of Construction	(2,801,233)
12		
13	NET BOOK COSTS	225,142,830
14		
15		
16	<u>Revenues & Expenses</u>	
17		
18	400 Operating Revenues	38,472,022
19		
20	403 - 407 Depreciation & Amortization Expenses	4,229,189
21	409 Federal & State Income Taxes	2,898,412
22	408 Other Taxes	1,386,989
23	Other Operating Expenses	22,383,262
24	TOTAL Operating Expenses	30,897,852
25		
26	Net Operating Income	7,574,170
27		
28	415-421.1 Other Income	0
29	421.2-426.5 Other Deductions	0
30		
31	NET INCOME	7,574,170
32		
33		
34	<u>Customers (Intrastate Only)</u>	
35		
36	Year End Average:	
37	Residential	25,518
38	Commercial	4,696
39	Industrial	211
40	Other	41
41		
42	TOTAL NUMBER OF CUSTOMERS	30,466
43		
44		
45	<u>Other Statistics (Intrastate Only)</u>	
46		
47	Average Annual Residential Use (Kwh)	11,522
48	Average Annual Residential Cost per (Kwh) (Cents) *	4.78
49	* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
50	Average Residential Monthly Bill	\$45.85
51	Gross Plant per Customer	\$9,671.78

Sch. 30 MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Bigfork	N. A.	2,328	657	30	3,015
2	Columbia Falls	2,942	2,673	617	42	3,332
3	Kalispell	11,917	10,165	2,781	267	13,213
4	Kila	N. A.	205	42		247
5	Lakeside	N. A.	940	250	7	1,197
6	Libby	2,532	4,339	1,241	65	5,645
7	Rollins	N. A.	255	54	4	313
8	Sommers	N. A.	586	164	10	760
9	Swan Lake	N. A.	169	37	1	207
10	Whitefish	4,368	4,611	1,160	29	5,800
11						0
12						0
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20						0
21						0
22						0
23						0
24						0
25						0
26						0
27						0
28						0
29						0
30						0
31						0
32						0
33	TOTAL Montana Customers	21,759	26,271	7,003	455	33,729

MONTANA EMPLOYEE COUNTS

	<u>Department</u>	<u>Year Beginning</u>	<u>Year End</u>	<u>Average</u>
1	Big Fork	2	2	2
2	Facilities Engineering		1	1
3	Kalispell District	33	35	34
4	Kalispell Power	5	5	5
5	Libby District	10	10	10
6	Montana Area	5	6	6
7	Whitefish District	11	10	11
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				
53	TOTAL Montana Employees	66	69	68

Sch. 32 **MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) --- In (000's)**

	Project Description	Total Company	Total Montana
1	THIRD AC PURCHASE FROM BPA	32,250	548
2	MEAD-PHOENIX 500 KV LINE	19,000	323
3	DIXONVILLE-MERIDIAN 500KV LINE 91 CONST	17,787	302
4	RESOURCE ACQUISITION-JAMES RIVER CAMAS COGE	14,134	240
5	RELOCATE TRANS LINE FOR SLC AIRPORT	12,678	215
6	WYODAK RELOCATE LOWER COAL	11,494	188
7	TRAIL MOUNTAIN	10,061	165
8	COTTONWOOD PREP PLANT - FINE COAL CIRCUIT	10,059	171
9	DAVE JOHNSTON PLANT - PURCHASE WATER RIGHTS	9,125	155
10	MERIDIAN 500KV SUB CONST BUS/D-M LN POS SHARE	8,380	142
11	MERWIN HATCHERY	8,227	229
12	JORDAN 138/46 KV SUBSTATION AND TRANSMISSION	6,159	105
13	WYODAK REPLACE HIGH VOLTAGE FIELDS IN PRECIP	6,001	102
14	THERMOPOLIS - HILLTOP 115KV LINE	5,753	98
15	TAYLRSVL 138/46 KV XFMR AND 138 KV LINE TO MIDVA	5,546	94
16	SOCC-PURCHASE NEW ENERGY MGT. COMPUTER SYS	5,317	90
17	NAUGHTON 270: ASH POND IMPROVEMENTS/EXPANS	4,857	83
18	AUTOMATED MAPPING PROJECT EXPENSES	4,842	80
19	NAUGHTON 270: S02 COMPLIANCE STUDY	4,458	76
20	COTTONWOOD MINE - MINE EXTENSION 1993	4,393	72
21	BEND-BUILD 69KV LINE TO PELTON RE-REG	3,990	68
22	BPA ALVEY 500KV SUBSTATION-CONSTRUCT BY BPA	3,614	61
23	DJ#0--UNIT #0 COAL UNLOADING FACILITY	3,543	60
24	PARK CITY AREA BACKUP	3,514	60
25	DATA INTEGRATION PROTOTYPE	3,452	57
26	RSC ACQ - WEST SIDE CTS	3,435	58
27	MALIN SUB - INSTL 2ND 500-230KV TRANSF BANK	3,370	57
28	DIXONVILLE 500KV SUB CONSTRUCT STATION SHARE	3,277	56
29	LINE 87 - REBUILD LINE SLIDING INTO OCEAN	3,255	55
30	GLEN CANYON - NAVAJO TIE LINE	2,800	48
31	JB UNIT 1 CONDENSATE POLISHER	2,696	46
32	APS COMBUSTION TURBINES - ENGINEERING	2,672	45
33	CENTRALIA MINE: (4) 190 HAUL TRUCKS	2,616	43
34	DEER CREEK MINE - MINE EXTENSION 1993	2,588	42
35	COVE SUB-CONSTR NEW COVE 230-69KV SUB	2,471	42
36	N UMPQUA RELICENSING	2,441	68
37	RELATIONAL MPCs	2,415	40
38	RIVERDALE 46 KV SUBSTATION - 3 YEAR REBUILD	2,339	40
39	INFO RESOURCES INTEGRATION PROJECT	2,273	37
40	BRIDGER MINE - DRAGLINE TUB (UNIT # 844)	2,184	36
41	1993 BOOM RECONSTRUCTION	2,062	34
42	COTTONWOOD MINE - FAN INSTALLATION	2,043	33
43	HUNTINGTON PLANT #1 COOLING TOWER FILL	2,034	35
44	HUNTINGTON PLANT #2 COOLING TOWER FILL	2,034	35
45	SERVICE TO THIOKOL & MORTON AT 138 KV	1,951	33
46	TIMPIE-SKUNK RIDGE 46 KV LINE & SWITCHRACK	1,819	31
47	DAVE JOHNSTON MINE: PURCHASE (1) SHOVEL	1,778	29
48	COLSTRIP PROJECT BETTERMENTS	1,683	29
49	TOOELE-DUGWAY #2 46 KV LINE	1,670	28
50	TRANS PLNG PRE-SWIP	1,600	27
51	115 LN PILOT BUTTE CHINA HAT	1,594	27
52	ALL OTHER	524,012	N/A
53	TOTAL	803,743	4,838

Sch. 33		TOTAL SYSTEM & MONTANA PEAK AND ENERGY				
		System				
		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
1	Jan.	09	0800	6,794	5,193,052	962,816
2	Feb.	05	0800	6,682	4,753,931	996,338
3	Mar.	09	0800	6,242	4,766,749	1,041,512
4	Apr.	07	0900	6,137	4,450,507	850,408
5	May	18	1100	6,159	4,797,788	954,987
6	Jun.	23	1400	6,953	4,800,576	891,876
7	Jul.	27	1500	6,767	5,268,993	1,142,260
8	Aug.	13	1600	7,011	5,296,389	1,189,515
9	Sep.	03	1400	6,064	4,757,462	1,098,143
10	Oct.	15	0800	6,277	4,970,217	1,119,371
11	Nov.	24	0800	7,028	5,105,450	1,088,173
12	Dec.	04	0800	7,258	5,477,347	983,213
13	TOTAL				59,638,461	12,318,612

		Montana				
		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
14	Jan.	20	0900	132	91,737	17,086
15	Feb.	04	1000	125	85,682	17,681
16	Mar.	09	0800	118	84,376	18,483
17	Apr.	08	0900	115	77,331	15,091
18	May	12	0800	102	76,963	16,947
19	Jun.	24	1200	97	76,205	15,827
20	Jul.	17	1100	98	76,348	20,271
21	Aug.	24	0900	103	78,642	21,109
22	Sep.	18	0900	108	79,102	19,488
23	Oct.	16	1000	117	82,696	19,864
24	Nov.	24	0800	133	90,790	19,311
25	Dec.	30	1100	164	106,415	17,448
26	TOTAL				1,006,287	218,606

Sch. 34		TOTAL SYSTEM Sources & Disposition of Energy		
	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	48,934,365	Sales to Ultimate Consumers (Include Interdepartmental)	41,511,308
3	Nuclear	114,346		
4	Hydro - Conventional	2,630,055	Requirements Sales for Resale	1,101,300
5	Hydro - Pumped Storage			
6	Other	79,036	Non-Requirements Sales for Resale	12,318,612
7	(Less) Energy for Pumping			
8	NET Generation	51,757,802	Energy Furnished Without Charge	160
9	Purchases	8,150,219		
10	Power Exchanges		Energy Used Within Electric Utility	80,608
11	Received	22,149,119		
12	Delivered	22,058,780	Total Energy Losses	4,626,473
13	NET Exchanges	90,339		
14	Transmission Wheeling for Others			
15	Received	1,438,392		
16	Delivered	1,438,392		
17	NET Transmission Wheeling	0		
18	Transmission by Others Losses	(359,899)	TOTAL	59,638,461
19	TOTAL	59,638,461		

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	392.0	2,842,970
2	Thermal	Craig Units #1 & #2	Craig, Colorado	177.0	925,543
3	Thermal	Hayden Plant	Hayden, Colorado	84.0	375,737
4	Thermal	Colstrip Unit #3 & #4	Colstrip, Montana	147.0	1,134,348
5	Thermal	Carbon Plant	Castle Gate, Utah	174.0	1,308,130
6	Thermal	Gadsby Plant	Salt Lake City, Utah	101.0	453,758
7	Thermal	Hunter Plant	Castle Dale, Utah	1,029.0	7,445,537
8	Thermal	Huntington Plant	Huntington, Utah	842.0	6,168,469
9	Thermal	Centralia Plant	Centralia, Washington	624.0	4,540,578
10	Thermal	Dave Johnston Plant	Glenrock, Wyoming	787.0	6,050,195
11	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,627.0	10,801,447
12	Thermal	Wyodak Plant	Gillette, Wyoming	278.0	2,239,218
13	Thermal	Naughton Plant	Kemmerer, Wyoming	683.0	4,462,066
14	Geothermal	Blundell Plant	Milford, Utah	25.0	186,369
15	Combustion Turbine	Little Mountain Plant	Ogden, Utah	15.0	79,036
16	Nuclear	Trojan Plant	Rainier, Oregon	29.0	114,346
17	Hydro	Copco #1	Copco, California	24.0	35,256
18	Hydro	Copco #2	Copco, California	28.0	46,805
19	Hydro	Fall Creek	Copco, California	2.2	11,248
20	Hydro	Iron Gate	Hornbrook, California	15.0	44,911
21	Hydro	Ashton	Ashton, Idaho	7.2	30,449
22	Hydro	Cove	Grace, Idaho	7.2	19,613
23	Hydro	Grace	Grace, Idaho	33.2	96,310
24	Hydro	Last Chance	Grace, Idaho	1.4	4,300
25	Hydro	Oneida	Preston, Idaho	21.4	32,218
26	Hydro	Paris	Paris, Idaho	0.8	991
27	Hydro	Soda	Soda, Idaho	8.1	16,478
28	Hydro	St. Anthony	St. Anthony, Idaho	0.6	2,279
29	Hydro	Bigfork	Bigfork, Montana	4.0	27,810
30	Hydro	Bend	Bend, Oregon	1.1	3,970
31	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	38,870
32	Hydro	Clearwater #2	Toketee Falls, Oregon	25.0	35,047
33	Hydro	Cline Falls	Redmond, Oregon	1.0	2,133
34	Hydro	Eagle Point	Eagle Point, Oregon	3.0	10,751
35	Hydro	East Side	Klamath Falls, Oregon	3.0	12,143
36	Hydro	Fish Creek	Toketee Falls, Oregon	13.0	37,488
37	Hydro	John C. Boyle	Keno, Oregon	43.0	68,960
38	Hydro	Lemolo #1	Toketee Falls, Oregon	29.0	83,674
39	Hydro	Lemolo #2	Toketee Falls, Oregon	36.0	118,631
40	Hydro	Powerdale	Hood River, Oregon	6.0	33,996
41	Hydro	Prospect #1	Prospect, Oregon	4.0	18,948
42	Hydro	Prospect #2	Prospect, Oregon	36.0	186,723
43	Hydro	Prospect #3	Prospect, Oregon	7.0	16,274
44	Hydro	Prospect #4	Prospect, Oregon	1.0	3,906
45	Hydro	Slide Creek	Toketee Falls, Oregon	20.0	63,097
46	Hydro	Soda Springs	Toketee Falls, Oregon	13.0	47,057
47	Hydro	Stayton	Stayton, Oregon	0.6	2,763
48	Hydro	Toketee	Toketee Falls, Oregon	31.0	163,176
49	Hydro	Wallowa Falls	Joseph, Oregon	1.1	3,313
50	Hydro	West Side	Klamath Falls, Oregon	0.6	124
51	Hydro	American Fork	Plesant Grove, Utah	0.1	4,580
52	Hydro	Beaver - Upper	Beaver, Utah	2.2	8,115

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
53	Hydro	Cutler	Collinston, Utah	25.5	26,350
54	Hydro	Fountain Green	Fountain Green, Utah	0.1	477
55	Hydro	Granite	Salt Lake City, Utah	0.5	3,168
56	Hydro	Gunlock	Gunlock, Utah	0.6	1,873
57	Hydro	Olmsted	Orem, Utah	5.3	11,282
58	Hydro	Pioneer	Ogden, Utah	2.6	7,772
59	Hydro	Sand Cove	Sand Cove, Utah	0.5	1,740
60	Hydro	Snake Creek	Midway, Utah	0.2	901
61	Hydro	Stairs	Salt Lake City, Utah	1.2	3,647
62	Hydro	Veyo	Veyo, Utah	0.3	559
63	Hydro	Weber	Uintah, Utah	3.2	11,433
64	Hydro	Condit	Underwood, Washington	15.0	68,422
65	Hydro	Drop	Naches, Washington	1.0	5,797
66	Hydro	Merwin	Ariel, Washington	149.0	331,108
67	Hydro	Naches	Naches, Washington	6.0	20,628
68	Hydro	Swift #1	Cougar, Washington	237.0	433,519
69	Hydro	Yale	Amboy, Washington	130.0	372,892
70	Hydro	Viva Naughton	Kemmerer, Wyoming	0.7	1,297
71	Pumping	Lifton	Lifton, Idaho		(5,217)
72					
73		Total Net Generation			51,757,802
74					
75		<u>POWER PURCHASES A/C 555</u>			
76					
77	Albany, City of		(1)		59
78	Alturas Cemetery District		09-30-1983		2
79	Anaheim, City of		(1)		1,035
80	Arizona Public Service Company		(2)		102,169
81	Arizona Public Service Company		(1)		77,340
82	Ashland, City of		(3)		1,622
83	BC Hydro		(1)		38,807
84	Beaver City		(4)		74
85	Bell Mountain Power		01-02-2020		1,019
86	Biomass One, Limited Partnership		01-31-2010		156,794
87	Birch Creek Hydro		08-21-2019		11,890
88	Black Hills Power & Light Company		06-30-2012		46,222
89	Black Hills Power & Light Company		(1)		2,215
90	Blanding City		(4)		1,069
91	Bogus Creek		12-31-2017		1,177
92	Boise Cascade Corporation		(1)		347
93	Bonneville Power Administration		(5)		
94	Bonneville Power Administration		(6)		
95	Bonneville Power Administration		(1)		336,079
96	Boston Power		12-31-2004		338
97	Boyd, James		12-31-2003		2,003
98	CDM Hydro		12-04-2019		21,877
99	Central Oregon Irrigation District		12-31-2018		14,964
100	Champion International Corp.		06-30-1994		27,821
101	Chelan County Public Utility Dist. No. 1		.08-31-2018		304,884
102	Chelan County Public Utility Dist. No. 1		(1)		17,129
103	Colockum Transmission Company		(1)		160
104	Colorado Public Service Company		(1)		164,468

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWh
105	Colorado Ute Electric Associates		(1)		28,220
106	Columbia Storage Power Exchange		(7)		261,286
107	Cook Electric		12-31-2017		6,548
108	Coos Curry Electric Cooperative		(4)		66
109	Cowlitz County Public Utility Dist. No. 1		(1)		554
110	Curtiss Livestock		12-31-1993		72
111	DAW Forest Products Company		(1)		1,570
112	Deer Creek Water Control District		(1)		588
113	Deseret Generation & Trans. Coop.		(1)		451,964
114	Difani, Chris		04-30-2007		45
115	Douglas County Public Utility Dist. No. 1		08-31-2018		258,692
116	Douglas County Public Utility Dist. No. 1		(1)		31,439
117	DR Johnson Lumber Company		12-31-2006		63,299
118	El Paso Electric Company		(1)		3,865
119	Eugene Water & Electric Board		(1)		16,956
120	Falls Creek		12-31-2019		9,753
121	Farmers Irrigation #2		12-31-2010		16,962
122	Fery, Lloyd		12-31-1993		275
123	Fillmore City		(4)		77
124	Fox, Marian		(4)		1
125	FS Industries Limited		(1)		2,095
126	Galesville Dam		12-31-2021		1,410
127	General Chemical Company		(1)		4,683
128	Georgetown Power		07-02-2019		1,761
129	Grand Valley Rural Power Lines		(4)		102
130	Grant County Public Utility Dist. No. 2		(8)		87,600
131	Grant County Public Utility Dist. No. 2		10-31-2005		586,164
132	Grant County Public Utility Dist. No. 2		10-31-2005		828,254
133	Grant County Public Utility Dist. No. 2		(1)		86,948
134	Idaho Falls, City of		11-02-2023		40,282
135	Idaho Power Company		(1)		8,625
136	Ingram Warm Springs Ranch		05-31-2021		4,354
137	Intermountain Power Project		06-15-2027		352,725
138	Lacomb Hydro		12-31-2018		2,401
139	Lagoon Corporation		12-31-1993		100
140	Lake Siskiyou		12-31-2020		15,724
141	Lehi Cogeneration Associates		03-29-1993		15,120
142	Los Angeles, City of		(1)		19,775
143	Luckey, Paul		12-31-2013		306
144	Middlefork Irrigation District		12-31-2004		19,772
145	Mink Creek Hydro		12-31-2021		5,514
146	Montana Power Company		(9)		131,760
147	Montana Power Company		(1)		9,112
148	Morgan City		(4)		21
149	Mountain Energy		12-31-2004		51
150	Murray City		(4)		207
151	Nephi City		(4)		25
152	New Mexico Public Service Company		(1)		329,519
153	Nichols Gap		12-31-2021		1,866
154	Nicholson Sunnybar Ranch		06-27-2020		1,911
155	North Fork Sprague		12-31-2023		1,376
156	Odell Creek		12-31-2010		84

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
157	Opal Springs		12-31-2020		25,609
158	Ormsby, Leslie		12-31-1993		11
159	O.J. Power Company		03-04-2021		335
160	Pacific Gas & Electric Company		(1)		9,970
161	Pancheri, Inc.		03-01-2013		84
162	Plains Electric		(1)		35,219
163	Platte River Power Authority		(1)		63,656
164	PLM, Inc		12-31-2013		489
165	Porcupine Reservoir Company		01-05-2016		
166	Portland General Electric Company		(10)		24,000
167	Portland General Electric Company		(1)		14,640
168	Preston City Hydro		02-24-2017		2,734
169	Provo City		(4)		183
170	Puget Sound Power & Light Company		(1)		45,142
171	Riverside, City of		(1)		600
172	Rocky Mountain Generation Cooperative		(1)		200,783
173	Rousch, Neil		12-31-1993		251
174	Royal Oak		12-31-1998		
175	Salt River Project		(1)		184,553
176	Salt River Project		(15)		
177	San Diego Gas & Electric Company		(1)		8,252
178	Santiam Water Control District		12-31-2019		1,078
179	Seattle City Light		(1)		2,375
180	Sierra Pacific Power Company		(1)		385
181	Slate Creek		12-31-2018		8,978
182	Solar Research		12-31-2009		527
183	Southern California Edison Company		(1)		86,869
184	Southern California Edison Company		(15)		
185	Southern California Edison Company		(15)		7,389
186	Southwestern Public Service Company		(1)		89,956
187	Spanish Fork City		(4)		44
188	Springville City		(4)		23
189	Strawberry Electric Service District		(1)		114
190	Tacoma City Light		(1)		10,309
191	Teton Generation Station		02-02-2020		1,550
192	Thayne Ranch Hydro		12-31-2015		1,522
193	TKO		01-01-2013		250
194	Tri-State Generation & Transmission		(11)		856,190
195	Tucson Electric Power Company		(1)		117,502
196	United States Bureau of Reclamation		10-06-2000		37,141
197	United States Bureau of Reclamation		(1)		10,953
198	Utah Assoc. Municipal Power Systems		(1)		25,433
199	Walla Walla, City of		12-31-2012		15,290
200	Warm Springs Forest Products Industry		(1)		1,988
201	Warm Springs Power Enterprises		12-31-2001		69,117
202	Washington Public Power Supply System		(12)		584,994
203	Washington Water Power Company		(13)		439,200
204	Washington Water Power Company		(14)		20,100
205	Washington Water Power Company		(1)		64,031
206	West Kootenay Power & Light Company		(1)		11,917
207	Western Area Power Administration		(1)		5,775

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak - MW	Annual Energy - MWH
208	Westinghouse		12-15-2022		7,432
209	White, J.E.		12-31-2017		936
210	Whitmore Oxygen		(1)		1,822
211	Whitney, A.C.		None		2
212	Wiggins, Duane		12-31-1993		4
213	Yakima Tieton		12-31-2005		8,197
214	System Deviation		(16)		872
215					
216		Total Power Purchases			8,150,219
217					
218		Net Exchanges			90,339
219					
220		Transmission by Others Losses			(359,899)
221					
222		Total Sources			59,638,461
223					
224					
225	Notes:				
226	(1) Non-firm.				
227	(2) Arizona Public Service - Contract Termination Date: Oct. 31, 2020.				
228	(3) City of Ashland - Contract Termination Date: Upon 30 days written notice.				
229	(4) Under electric service agreement subject to termination upon timely notification.				
230	(5) Bonneville Power Administration - Contract Termination Date: August 31, 2011.				
231	(6) Bonneville Power Administration - Contract Termination Date: March 31, 2003.				
232	(7) Columbia Storage Power Exchange - Contract Termination Date: March 31, 2003.				
233	(8) Grant County PUD No. 2 - Contract Termination Date: Later of September 1, 1988				
234	or 2 years written notice.				
235	(9) Montana Power Company - Contract Termination Date: December 31, 1995.				
236	(10) Portland General Electric Co. - Contract Termination Date: December 18, 2001.				
237	(11) Tri-State Generation & Trans. - Contract Termination Date: December 31, 2020.				
238	(12) Washington Public Power Supply System - Contract Termination Date: June 30, 1996.				
239	(13) Washington Water Power Co. - Contract Termination Date: December 31, 1995.				
240	(14) Washington Water Power Co. - Contract Termination Date: December 31, 1995.				
241	(15) Short-term firm, where duration of commitment for service is one year or less.				
242	(16) Not applicable; adjustment for inadvertent interchange.				
243					
244					
245					
246					
247					
248					
249					
250					
251					
252					
253					
254					
255					
256					
257					
258					

**1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration**

<u>Plant</u>	<u>Date of Outage</u>	<u>Cause of Outage</u>	<u>Duration</u>
<u>Large Plants</u>			
Cutler	None		
Grace	21-Feb-92	#4 Unit Tripped - Step-Up transformer trouble	26 hrs 25 min
	28-Dec-92	#5 Unit Tripped - Bearing failure	112 hrs 45 min
Olmstead	8-Jun-92	#4 Unit offline - Central Utah Water Conserv. District shut off water supply after non company truck carrying ammonium nitrate crashed into the river.	27 hrs
Oneida	1-Jan-92	#2 Unit taken offline - excessive unit vibration	1381 hrs 32 min
	27-Feb-92	#2 Unit offline - upper guide bearing damage	430 hrs 55 min
	17-Mar-92	#2 Unit offline - upper guide bearing damage. Note: unit overhauled and cleaned during extended outage. During outage period new butterfly valves installed ahead of Units #1 and #2 to replace old Johnson valves	6943 hrs 40 min
Soda	None		
Merwin	30-Jan-92	#2 Unit - upper slip ring went to ground	123 hrs 27 min
Yale	None		
Swift No. 1	None		
Copco No. 1	15-Jul-92	Relay base shorting out	147 hrs 56 min
Copco No. 2	22-Apr-92	Field breaker went out	165 hrs
	29-Aug-92	BFV limit switch out of adjustment	26 hrs
	20-Nov-92	Relay would not latch	70 hrs 35 min
J. C. Boyle	None		
Iron Gate	None		
Soda Springs	None		
Slide Creek	None		
Fish Creek	None		
Clearwater No. 1	None		

1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration

<u>Plant</u>	<u>Date of Outage</u>	<u>Cause of Outage</u>	<u>Duration</u>
Clearwater No. 2	None		
Lemolo No. 1	4-Sep-92	Turbin bearing over temp	168 hrs
Lemolo No. 2	None		
Toketee	21-Feb-92	Solid state excieter B/O. Bad diode and blown fuse.	310 hrs 55 min
	10-Apr-92	Alarm on S/D, possible turbine bearing out	3431 hrs 5 min
	9-Dec-92	Hot packing. Replaced packing.	45 hrs 5 min
	13-Dec-92	Oil leak at turbin bearing probe	28 hrs 38 min
Prospect No. 2	None		
<u>Small Plants</u>			
American Fork	1-Apr-92	Flowline leak - offline until section of flowline could be replaced.	503 hrs 40 min
Ashton	None		
Beaver - Upper	None		
Bend	None		
Bigfork	None		
Cline Falls	None		
Conduit	None		
Cove	None		
Drop	26-Feb-92	Canal failure	336 hrs 45 min
	24-Jul-92	Canal washout caused by failure of Naches-Selah flume	98 hrs 10 min
Eagle Point	None		
East Side	None		

1992 Hydro Power Plant Outages
Exceeding 24 Hour Duration

<u>Plant</u>	<u>Date of Outage</u>	<u>Cause of Outage</u>	<u>Duration</u>
Fall Creek		Water actuator out	out entire year
Fountain Green	1-Jan-92	Unit tripped - under voltage condition	37 hrs 30 min
	2-May-92	Unit tripped - under voltage condition	37 hrs 45 min
	9-May-92	Unit tripped - under voltage condition	98 hrs 50 min
	4-Jun-92	Unit tripped - under voltage condition	96 hrs
	3-Oct-92	Unit tripped - under voltage condition	25 hrs 35 min
Granite	12-Aug-92	Unit offline - Flowline Failure - excessive leakage . Rebuilt section of flume	2090 hrs 22 min
Gunlock	None		
Last Chance	16-Aug-92	#1, #2, #3 units offline - Control computer trouble	192 hrs 15 min
	24-Aug-92	#1, #2, #3 units offline - Hydraulic gate control failure	201 hrs 35 min
Naches	26-Feb-92	Canal failure	336 hrs 36 min
	30-Apr-92	#2 Unit offline - bearing failure	65 hrs
	24-Jul-92	Canal washout caused by failure of Naches-flume	98 hrs 10 min
Paris	None		
Poineer	18-Apr-92	#6 Unit offline - Flowline failure. Several wood-staves were replaced.	50 hrs 45 min
Powerdale	24-Oct-92	Failure of pneumatic control valve on Johnson valve	41 hrs 2 min
Prospect 1	None		
Prospect No. 3	2-Feb-92	D. C. short	24 hrs 20 min
Prospect No. 4	19-Feb-92	Hot bearing	160 hrs 20 min
Sand Cove	26-Jan-92	Unit tripped - flowline damaged. Repaired shrot section of steel pipeline.	142 hrs
Snake Creek	2-Nov-92	#1 Unit tripped - Protective relay trouble	32 hrs 50 min
Stairs	1-Aug-92	Unit offline - Replace exciter rotor	122 hrs 15 min

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon #1						
1.	01/16/92 23:23	-	01/17/92 13:49	Forced	14.43	981.44
	Descr: WATERWALL TUBE LEAK IN THE VICINITY OF A WATERWALL SOOT-BLOWER					
2.	04/10/92 23:20	-	05/18/92 11:42	Planned	900.37	61,224.89
	Descr: UNIT 1 PLANNED OVERHAUL					
3.	05/18/92 12:58	-	05/18/92 15:02	Forced	2.07	140.49
	Descr: FEEDWATER REGULATING VALVE FAILURE					
4.	05/21/92 00:58	-	05/21/92 04:44	Forced	3.77	256.09
	Descr: TRIPPED ON TEST					
5.	05/21/92 04:44	-	05/21/92 05:46	Forced	1.03	70.24
	Descr: ATTEMPT TO RE-SYNCHRONIZE FAILED					
6.	07/27/92 11:48	-	07/27/92 16:10	Forced	4.37	296.89
	Descr: OIL LEAK ON CIRCUIT BREAKER 171					
7.	07/27/92 16:10	-	07/27/92 19:17	Forced	3.12	211.89
	Descr: START-UP FAILURE					
8.	08/07/92 12:43	-	08/08/92 05:12	Forced	16.48	1,120.84
	Descr: BOILER TUBE LEAK IN THE ECONOMIZER SECTION					
9.	08/22/92 21:44	-	08/23/92 00:00	Forced	2.27	154.09
	Descr: UNIT TRIP DUE TO OPERATOR ERROR					
*** Unit Summary for Carbon #1 for the year 1992 =					947.91	64,456.86
Carbon #2						
1.	01/15/92 00:05	-	01/15/92 13:42	Forced	13.62	1,429.68
	Descr: WATERWALL TUBE LEAK IN THE VICINITY OF THE WALL SOOT BLOWER					
2.	02/27/92 12:39	-	02/27/92 13:39	Forced	1.00	105.00
	Descr: OPERATOR ERROR - TRIP DUE TO LOSS OF FANS ON BOILER					
3.	02/27/92 13:39	-	02/27/92 18:00	Forced	4.35	456.75
	Descr: RELIEF VALVE BONNET BLEW OFF ON RECIRC LINE ON THE #2-1 BOILER FEED					
4.	02/27/92 18:00	-	02/27/92 21:51	Forced	3.85	404.25
	Descr: CONDENSATE SAMPLE LINE FOR LAB IS IN NEED OF REPAIR					
5.	05/14/92 09:24	-	05/14/92 14:14	Forced	4.83	507.47
	Descr: UNIT TRIP DUE TO HUMAN ERROR AT SWITCHYARD					
6.	09/02/92 21:45	-	09/04/92 21:29	Forced	47.73	5,011.97
	Descr: REPAIR SUPERHEATER TUBE LEAK					

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Centralia #1								
15.	12/12/92	17:12	-	12/12/92	21:49	Forced	4.62	3,023.48
Descr: EH CONTROL PROBLEMS								
16.	12/12/92	21:49	-	12/12/92	22:44	Forced	0.92	599.98
Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN								
17.	12/13/92	01:30	-	12/13/92	02:27	Forced	0.95	622.25
Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN								
18.	12/13/92	02:27	-	12/13/92	08:50	Forced	6.38	4,180.87
Descr: DATA LOGGER PROBLEMS								
19.	12/13/92	08:50	-	12/13/92	15:12	Forced	6.37	4,169.73
Descr: TURBINE TRIP SOLENOID ACTIVATED - CAUSE UNKNOWN								
20.	12/25/92	18:04	-	12/25/92	19:32	Forced	1.47	960.23
Descr: SOE 1ST REPORT - UNDERFREQUENCY. THE UNDERFREQUENCY SIGNAL APPEARS TO								
21.	12/25/92	20:43	-	12/26/92	00:45	Forced	4.03	2,641.62
Descr: SOE 1ST OUT REPORT - SOLENOID TRIP. SUSPECT PROBLEM WITH UNDERFREQUENC								
*** Unit Summary for Centralia #1 for the year 1992 =							1,047.16	685,878.69
Centralia #2								
1.	02/07/92	00:21	-	02/12/92	14:01	Maint.	133.67	87,551.23
Descr: WATERWALL TUBE LEAK IN BOILER THROAT AREA								
2.	02/28/92	17:48	-	02/29/92	01:57	Forced	8.15	5,338.25
Descr: TURBINE E-H SYSTEM LEAK REPAIR								
3.	11/14/92	00:00	-	11/16/92	09:30	Forced	57.50	37,662.50
Descr: WATERWALL TUBE LEAK								
*** Unit Summary for Centralia #2 for the year 1992 =							199.32	130,551.98
Cholla #4								
1.	02/16/92	19:07	-	02/17/92	23:28	Forced	28.35	9,922.50
Descr: UNIT OFF LINE TO REPAIR BOILER TUBE LEAK								
2.	02/17/92	23:28	-	02/22/92	04:40	Forced	101.20	35,420.00
Descr: METAL FAILURE CAUSED LINE RUPTURE FLOODING CIRCULATING WATER PUMPMOTOR								
3.	02/22/92	06:40	-	02/22/92	07:56	Forced	1.27	443.10
Descr: LOSS OF FEEDWATER CONTROL WHEN TRANSFERRING "B" BOILER FEED PUMP FROM								

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #1								
4.	07/02/92	10:00	-	07/06/92	04:42	Forced	90.70	9,523.50
	Descr: CONTINUED WITH WATERWALL TUBE LEAK REPAIRS							
5.	07/06/92	06:54	-	07/07/92	16:08	Forced	33.23	3,489.47
	Descr: WATERWALL TUBE LEAK							
6.	07/07/92	16:08	-	07/07/92	17:40	Forced	1.53	160.97
	Descr: IGNITOR PROBLEMS ON STARTUP							
7.	07/07/92	17:40	-	07/07/92	20:31	Forced	2.85	299.25
	Descr: CONTINUED WITH WATERWALL REPAIRS							
8.	07/07/92	22:39	-	07/07/92	23:16	Forced	0.62	64.68
	Descr: HI DRUM LEVEL							
*** Unit Summary for Dave Johnston #1 for the year							177.40	18,626.80
Dave Johnston #2								
1.	01/22/92	13:12	-	01/22/92	14:33	Forced	1.35	141.75
	Descr: BOILER CONTROLS DUE TO #1 TRIP							
2.	01/30/92	00:20	-	01/30/92	07:42	Forced	7.37	773.43
	Descr: C PHASE OF DISCONNECT LOOSE							
3.	02/28/92	23:11	-	03/01/92	00:00	Forced	24.82	2,605.68
	Descr: AIR HEATER WASH							
4.	03/01/92	00:00	-	03/01/92	09:04	Forced	9.07	951.93
	Descr: AIR HEATER WASH							
5.	03/14/92	10:41	-	03/16/92	04:57	Forced	42.27	4,437.93
	Descr: PRIMARY SUPERHEAT TUBE LEAK							
6.	03/30/92	13:13	-	03/30/92	14:02	Forced	0.82	85.68
	Descr: VAC TRIP							
7.	04/03/92	23:34	-	04/06/92	14:00	Forced	61.43	6,450.47
	Descr: WATER WALL TUBE LEAKS							
8.	04/06/92	16:50	-	04/06/92	18:33	Forced	1.72	180.18
	Descr: HI DRUM LEVEL							
9.	05/15/92	23:24	-	06/10/92	10:49	Planned	611.42	64,198.68
	Descr:							
10.	06/11/92	10:03	-	06/12/92	17:43	Forced	31.67	3,324.93
	Descr: SUPERHEAT TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #3						
11.	10/18/92 13:01	-	10/19/92 08:40	Forced	19.65	4,323.00
	Descr: CLEAN SLAG SCREEN					
12.	10/20/92 12:35	-	10/20/92 14:28	Forced	1.88	414.26
	Descr: 3B PA DAMPER/DRAFT TRIP					
13.	10/20/92 15:54	-	10/20/92 16:25	Forced	0.52	113.52
	Descr: LOW VACUUM TRIP,DUE TO SJAE					
14.	10/20/92 17:56	-	10/20/92 18:47	Forced	0.85	187.00
	Descr: DRUM LEVEL TRIP,DUE TO MILLS					
15.	10/21/92 03:52	-	10/22/92 16:07	Forced	36.25	7,975.00
	Descr: CLEAN SLAG SCREEN					
16.	10/22/92 16:07	-	10/22/92 20:10	Forced	4.05	891.00
	Descr: 3A ID FAN DAMPER LEAK THRU					
17.	10/24/92 14:00	-	10/24/92 14:55	Forced	0.92	201.52
	Descr: DRAFT TRIP,CONTROL TUNING					
18.	10/28/92 07:20	-	10/28/92 08:14	Forced	0.90	198.00
	Descr: MFT,INVERTER FAILURE					
19.	10/28/92 09:28	-	10/28/92 11:52	Forced	2.40	528.00
	Descr: MFT,INVERTOR FAILURE					
20.	10/31/92 00:25	-	11/01/92 22:28	Maint.	46.05	10,131.00
	Descr: REBUILD SLAG SCREEN					
21.	12/20/92 02:55	-	12/22/92 13:57	Forced	59.03	12,987.26
	Descr: CLINKER IN THROAT					
*** Unit Summary for Dave Johnston #3 for the year					1,260.23	277,246.20

Dave Johnston #4

1.	01/28/92 02:14	-	01/28/92 10:00	Forced	7.77	2,485.12
	Descr: RELAY PROBLEMS IN SWITCHYARD					
2.	01/28/92 10:00	-	01/30/92 18:33	Forced	56.55	18,096.00
	Descr: TUBELEAK WATERWALL					
3.	01/30/92 18:34	-	01/30/92 19:02	Forced	0.47	149.12
	Descr: UNDER EXCITATION GEN. VOLTAGE CONTROL					
4.	03/20/92 19:14	-	03/24/92 16:54	Forced	93.67	29,973.12
	Descr: WATER WALL TUBE LEAK					

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston #4						
22.	10/17/92 21:51	-	10/17/92 23:01	Forced	1.17	373.12
	Descr: FLAME FAILURE,IGNITORS					
23.	11/20/92 12:25	-	11/20/92 16:50	Forced	4.42	1,413.12
	Descr: ELEC. SHORT IN PULV. CONTROLS					
24.	11/25/92 08:02	-	11/25/92 11:55	Forced	3.88	1,242.56
	Descr: B STARTER COOLER PUMP MOTOR FAILED					
25.	12/04/92 09:43	-	12/04/92 10:41	Forced	0.97	309.12
	Descr: INSTRUMENT ISOLATION ERROR					
26.	12/04/92 10:56	-	12/04/92 11:31	Forced	0.58	186.56
	Descr: COULD NOT GET COAL UP TO SILO					
27.	12/13/92 07:25	-	12/14/92 22:35	Forced	39.17	12,533.12
	Descr: TUBE LEAK C CORNER					
*** Unit Summary for Dave Johnston #4 for the year					420.35	134,503.36

Gadsby #3

1.	01/13/92 22:54	-	01/14/92 18:15	Maint.	19.35	1,935.00
	Descr: TUBE LEAK AT TOP ELEVATION OF FLEXIBLE SLIP SPACERS, NORTH SIDE OF FE-					
2.	01/14/92 18:15	-	01/14/92 19:15	Maint.	1.00	100.00
	Descr: INSTRUMENT AIR LINES TO BOTH FD AND ID FAN CONTROLS FROZEN. UNIT HAD B					
3.	01/14/92 19:15	-	01/15/92 04:33	Maint.	9.30	930.00
	Descr: APPARATUS MAINTENANCE HAD TO ADD 200 GALLONS OF OIL TO TRANSFORMER					
4.	05/09/92 00:17	-	05/09/92 20:30	Maint.	20.22	2,021.60
	Descr: TUBE LEAKS AT TOE OF WELDS, BOTH SIDES OF FEMALE SLIP SPACERS, SECOND					
5.	05/09/92 21:00	-	05/10/92 06:10	Forced	9.17	916.60
	Descr: NEED TO PURGE BOILER FOR STARTUP					
6.	10/30/92 23:09	-	12/01/92 11:48	Planned	756.65	75,665.00
	Descr: UNIT OFF LINE FOR SCHEDULED OVERHAUL.					
7.	12/15/92 21:37	-	12/15/92 23:15	Forced	1.63	163.30
	Descr: BAILEY WAS ATTEMPTING TO TUNE FURNACE DRAFT AND CAUSED DRAFT TRIP					
8.	12/16/92 06:53	-	12/16/92 08:49	Forced	1.93	193.30
	Descr: TRIP SEEMED TO BE CAUSED BY UNEXPLAINED LINK BETWEEN NEW BURNER MANAGE					
9.	12/16/92 11:54	-	12/16/92 14:11	Forced	2.28	228.30
	Descr: BOILER TRIP SEEMED TO BE CAUSED BY UNKNOWN LINK BETWEEN THE NEW BURNER					

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #1								
12.	09/03/92	22:31	-	09/11/92	22:07	Forced	191.60	75,682.00
	Descr: UNIT TRIP - 3 MILL DUCTS BLOWN UP							
13.	09/16/92	00:09	-	09/18/92	01:51	Maint.	49.70	19,631.50
	Descr: BOILER TUBE LEAK - SUPERHEAT							
14.	10/05/92	12:51	-	10/05/92	21:42	Forced	8.85	3,495.75
	Descr: UNIT TRIP - UPS SYSTEM TESTING							
15.	12/05/92	00:00	-	12/06/92	06:19	Forced	30.32	11,974.82
	Descr: BOILER TUBE LEAK (WATERWALL)							
*** Unit Summary for Hunter #1 for the year 1992 =							1,358.26	536,506.79
Hunter #2								
1.	01/05/92	08:04	-	01/05/92	10:55	Forced	2.85	1,125.75
	Descr: UNIT TRIP - #2-3 MCC TRIPPED							
2.	01/21/92	07:10	-	01/21/92	12:30	Forced	5.33	2,106.54
	Descr: UNIT TRIPPED - FW TRANSMITTER FROZEN							
3.	01/25/92	04:22	-	01/25/92	22:59	Forced	18.62	7,353.32
	Descr: UNIT OFF - REPAIR 2-5 MILL HOT AIR GATE							
4.	02/02/92	21:32	-	02/04/92	10:42	Forced	37.17	14,680.57
	Descr: OFF LINE FOR PRECIP WORK							
5.	02/22/92	19:30	-	02/22/92	21:30	Forced	2.00	790.00
	Descr: OFF LINE - LUMP COAL							
6.	02/29/92	05:45	-	03/01/92	00:00	Forced	18.25	7,208.75
	Descr: UNOT OFF LINE - CONDENSER TUBE LEAK							
7.	03/10/92	00:00	-	03/10/92	20:35	Forced	20.58	8,130.29
	Descr: UNIT OFF LINE - CONDENSER TUBE LEAK							
8.	06/12/92	00:00	-	06/13/92	14:15	Forced	38.25	15,108.75
	Descr: OFF LINE - PRECIP WORK							
9.	06/19/92	16:25	-	06/19/92	17:57	Forced	1.53	605.54
	Descr: OFF LINE - BCP DIFF TRIP							
10.	06/20/92	00:00	-	06/21/92	12:28	Forced	36.47	14,404.07
	Descr: OFF LINE FOR MILL AND PRECIP WORK							
11.	09/04/92	00:03	-	09/05/92	17:27	Forced	41.40	16,353.00
	Descr: UNIT OFF LINE - WATER IN COAL SILOS							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Hunter #3								
12.	08/27/92	12:53	-	08/27/92	15:09	Forced	2.27	895.07
Descr: UNIT TRIP, 3-1 BAGHOUSE TRIP								
13.	10/09/92	07:49	-	10/11/92	17:44	Forced	57.92	22,876.82
Descr: BOILER TUBE LEAK - PRIMARY SUPERHEAT								
14.	10/24/92	08:58	-	10/26/92	13:07	Forced	53.15	20,994.25
Descr: BOILER TUBE LEAK (REHEAT SECTION)								
*** Unit Summary for Hunter #3 for the year 1992 =							517.57	204,437.01

Huntington #1

1.	01/24/92	09:58	-	01/26/92	01:34	Forced	39.60	15,840.00
Descr: OFF LINE DUE TO BOILER ASH PLUGGAGE (HIGH ASH COAL).								
2.	06/25/92	00:18	-	06/25/92	04:10	Forced	3.87	1,546.40
Descr: TESTING TURBINE STOP VALVES, TURBINE TRIPPED, REASON UNDETERMINED, POS								
3.	10/24/92	22:30	-	10/25/92	12:00	Forced	14.50	5,800.00
Descr: FAILED								
4.	10/25/92	12:01	-	10/29/92	01:38	Forced	85.62	34,246.40
Descr: MOTOR BURNED UP DUE TO PUMP SHAFT LEAKS								
5.	10/29/92	02:11	-	10/29/92	03:42	Forced	1.52	606.40
Descr: PROBLEMS WITH MOV-12, TRYING TO PUT UNIT ON LINE AFTER TRIP								
6.	10/29/92	04:58	-	10/29/92	19:14	Forced	14.27	5,706.40
Descr: BOILER TRIP								
7.	10/29/92	19:56	-	10/31/92	20:07	Forced	48.18	19,273.20
Descr: BOILER TRIP								
*** Unit Summary for Huntington #1 for the year 1992 =							207.56	83,018.80

Huntington #2

1.	03/28/92	00:08	-	03/28/92	01:11	Forced	1.05	425.25
Descr: BOILER TRIP CAUSED BY ELECTRICAL CONTROLS.								
2.	03/28/92	02:11	-	05/15/92	09:47	Planned	1,158.60	469,233.00
Descr: TURBINE OFF LINE FOR GENERAL OVERHAUL								
3.	05/15/92	10:44	-	05/15/92	12:06	Forced	1.37	553.23
Descr: LOST BOILER DUE TO A FLAME SCANNER PROBLEM								
4.	05/15/92	12:44	-	05/15/92	13:58	Forced	1.23	499.37
Descr: LOW DRUM LEVEL								

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #1								
1.	01/17/92	06:42	-	01/17/92	07:33	Forced	0.85	442.00
	Descr: SWITCHYARD TRIP-LOST BORAH LINE.							
2.	01/24/92	14:18	-	01/25/92	14:25	Forced	24.12	12,540.32
	Descr: BTG TRIPPED BY OPERATOR. SUPERHEAT TUBE LEAK. FOUND TUBE LEAK IN REH							
3.	02/12/92	07:10	-	02/12/92	07:53	Forced	0.72	372.32
	Descr: BORAH LINE TRIP.							
4.	02/12/92	08:11	-	02/13/92	11:11	Forced	27.00	14,040.00
	Descr: LOW FURNACE AIR FLOW WHILE LOWERING LOAD TO REMOVE UNIT FROM SERVICE.							
5.	02/14/92	03:34	-	02/14/92	21:39	Forced	18.08	9,403.16
	Descr: MANUAL OPERATOR TRIP. REHEAT TUBE LEAK AT K-5.							
6.	03/14/92	01:06	-	03/15/92	07:34	Forced	30.47	15,842.32
	Descr: MANUAL OPERATOR TRIP. REHEAT TUBE LEAK PANEL 61 TUBE 5 & 6. FUEL OIL							
7.	03/15/92	21:04	-	03/16/92	15:04	Forced	18.00	9,360.00
	Descr: REHEAT TUBE LEAK.							
8.	03/18/92	08:06	-	03/19/92	05:33	Forced	21.45	11,154.00
	Descr: FLAME FAILURE TRIP-HAD THREE MILLS ON ABOVE 50%. SCANNERS TRIPPED WHI							
9.	03/27/92	23:51	-	04/27/92	00:09	Planned	719.30	374,036.00
	Descr: MANUAL BY OPERATOR. ANNUAL OVERHAUL. NOTE 72 HOURS SHOULD BE CHARGE							
10.	06/17/92	15:02	-	06/19/92	03:27	Forced	36.42	18,936.32
	Descr: CONTROL OPERATOR USED THE TURBINE TRIP BUTTON AT 000MW-SUPERHEAT TUBE							
11.	07/11/92	06:25	-	07/13/92	01:16	Forced	42.85	22,282.00
	Descr: WATERWALL TUBE LEAK.							
12.	07/13/92	04:50	-	07/13/92	05:50	Forced	1.00	520.00
	Descr: TURBINE TRIP, HIGH BACK PRESSURE. TRIPPED ABS LOW.							
13.	07/15/92	06:24	-	07/16/92	03:35	Forced	21.18	11,015.16
	Descr: OPERATOR TRIP. BOILER TUBE LEAK.							
14.	08/06/92	04:22	-	08/06/92	05:19	Forced	0.95	494.00
	Descr: TURBINE THRUST BEARING LOW LUBE OIL PRESSURE. HI. CIRC. WATER AND L/O							
15.	08/09/92	00:53	-	08/10/92	00:00	Forced	23.12	12,020.32
	Descr: BOILER TUBE LEAKS, 2 REHEATER (45-5, 14-6) AND ONE WATERWALL.							
16.	08/10/92	00:00	-	08/10/92	18:06	Forced	18.10	9,412.00
	Descr: INSPECT AND REPAIR CRACKS IN THE ID FANS.							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #2								
1.	01/17/92	12:08	-	01/17/92	13:08	Forced	1.00	520.00
	Descr: SWITCHYARD TRIP-LOST KINPORT LINE.							
2.	01/17/92	13:25	-	01/17/92	14:00	Forced	0.58	303.16
	Descr: LOSS OF IGNITION ENERGY-IGNITORS WOULD NOT SEAL IN.							
3.	01/28/92	01:04	-	01/29/92	05:00	Forced	27.93	14,525.16
	Descr: LOSS OF 22 APH MAIN AND AUX. DRIVE.							
4.	04/11/92	22:18	-	04/12/92	03:21	Forced	5.05	2,626.00
	Descr: OPERATOR TRIP. LOW VOLTAGE ON AUX. BUS. PROBLEM STARTED WHEN LIGHTIN							
5.	04/30/92	00:21	-	04/30/92	01:21	Forced	1.00	520.00
	Descr: SWITCHYARD TRIP. KINPORT LINE RELAYED. GENERATOR DC REGULATOR PROBLE							
6.	06/11/92	08:08	-	06/12/92	16:24	Forced	32.27	16,778.32
	Descr: UNIT CONTROL OPERATOR USED TURBINE TRIP BUTTON AT 000MW. #22 APH AND							
7.	06/19/92	00:33	-	06/20/92	23:48	Forced	47.25	24,570.00
	Descr: CONTROL BOARD TURBINE TRIP BUTTON BY CONTROL OPERATOR. SUPERHEAT TUBE							
8.	07/13/92	11:06	-	07/15/92	03:37	Forced	40.52	21,068.32
	Descr: OPERATOR INITIATED TRIP FROM BTG BOARD. DIVISION PANE; #5 TUBE LEAK.							
9.	07/17/92	15:05	-	07/17/92	16:14	Forced	1.15	598.00
	Descr: SWITCHYARD TRIP,KINPORT LINE TRIPPED AND TRIPPED ASSOCIATED UNIT (UNIT							
10.	08/19/92	04:05	-	08/19/92	05:21	Forced	1.27	658.32
	Descr: KINPORT LINE TRIP. KINPORT LINE LOADING. RELAY 552-22/AX GENERATOR B							
11.	09/08/92	23:48	-	09/10/92	22:48	Forced	47.00	24,440.00
	Descr: TUBE LEAK-SH PENDANT PLATEN WATER-COOLED SPACER.							
12.	09/10/92	22:48	-	09/13/92	23:16	Forced	72.47	37,682.32
	Descr: ID FAN INSPECTION AND REPAIR.							
13.	11/21/92	21:32	-	11/22/92	14:00	Forced	16.47	8,562.32
	Descr: OPERATOR TRIP. REPLACE BOILER DRUM SIGHT GLASS WATER-SIDE ISOLATION V							
14.	11/22/92	14:00	-	11/22/92	19:04	Forced	5.07	2,634.32
	Descr: REPAIR #22 PA FAN INLET VANE POSITIONER ON INBOARD SIDE.							
15.	11/23/92	03:52	-	11/23/92	04:48	Forced	0.93	485.16
	Descr: HI BACK PRESS.-LOST 21 CIRC. WTR. PUMP. UNIT RUNNING AT CONSTANT LOAD							
16.	11/26/92	05:32	-	11/26/92	08:16	Forced	2.73	1,421.16
	Descr: UNIT TRIP-LOST KINPORT LINE.							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #3								
13.	06/08/92	08:41	-	06/08/92	12:15	Forced	3.57	1,854.32
Descr: ELECTRICAL TRIP.								
14.	06/30/92	08:40	-	06/30/92	10:03	Forced	1.38	719.16
Descr: TURBINE MASTER TRIP. EHC FLUID PRESSURE LESS THAN 1200 PSI. BYPASS V								
15.	07/24/92	17:01	-	07/25/92	13:34	Forced	20.55	10,686.00
Descr: HIGH VIBRATION ON 4 TURBINE BEARING. WATERWALL TUBE LEAK REPAIRED WHI								
16.	08/12/92	06:16	-	08/12/92	07:30	Forced	1.23	641.16
Descr: GOSHEN LINE RELAYED.								
17.	08/12/92	07:30	-	08/12/92	13:34	Forced	6.07	3,154.32
Descr: MCC 324 AND MOTOR SUCTION OIL PUMP-#31 EHC PUMP CONTROL POWER TRANSFOR								
18.	08/12/92	13:34	-	08/12/92	14:30	Forced	0.93	485.16
Descr: SEDC TRIP-INSTANT TRIP-SEDC WAS NOT RESET. CLEAR TRIP AND ROLL TURBIN								
19.	08/29/92	06:10	-	08/29/92	07:13	Forced	1.05	546.00
Descr: SWITCHYARD TRIP. LOSS OF GOSHEN LINE.								
20.	09/30/92	23:47	-	10/02/92	09:02	Forced	33.25	17,290.00
Descr: DESLAG REHEATER. OPERATOR INITIATED WITH TURBINE TRIP PUSH BUTTON. D								
21.	10/02/92	09:02	-	10/03/92	02:28	Forced	17.43	9,065.16
Descr: WATERWALL TUBE LEAK.								
22.	10/03/92	06:19	-	10/03/92	08:37	Forced	2.30	1,196.00
Descr: TRIPPED BY OPERATOR AT 400 MW'S-HIGH TURBINE VIBRATION. #3 BEARING, 1								
23.	10/15/92	10:31	-	10/15/92	12:17	Forced	1.77	918.32
Descr: HOT P.A. DUCT PRESSURE-CONTRACTORS WORKING NEAR TRANSMITTER. P.A. DUCT								
24.	10/15/92	13:46	-	10/15/92	14:27	Forced	0.68	355.16
Descr: PA DUCT PRESSURE LOW. BURNT OUT RELAYS ON PA DUCT PRESSURE TIME DELAY								
25.	10/27/92	06:45	-	10/27/92	07:20	Forced	0.58	303.16
Descr: UNIT TRIP DUE TO KINPORT LINE TRIP-RAS ARMED.								
26.	10/27/92	07:20	-	10/28/92	01:13	Forced	17.88	9,299.16
Descr: UNIT OFF TO REPAIR SUPERHEATER PENDANT PLATEN TUBE LEAK.								
27.	11/10/92	03:15	-	11/10/92	15:03	Forced	11.80	6,136.00
Descr: PUSH BUTTON(OPERATOR). LOW BOILER PH, CONDENSER TUBE LEAK.								

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger #4								
12.	04/17/92	19:31	-	04/18/92	22:37	Forced	27.10	14,092.00
Descr: FLAME FAILURE. WATERWALL TUBE LEAK.								
13.	04/19/92	00:04	-	04/19/92	02:23	Forced	2.32	1,204.32
Descr: TOTAL FLAME FAILURE DURING START UP OF UNIT. 52 MINUTES TO HANG JUMPE								
14.	05/07/92	22:49	-	05/09/92	02:18	Forced	27.48	14,291.16
Descr: OPERATOR INITIATED DUE TO WATERWALL TUBE LEAK. BOILER TUBE LEAK, WATE								
15.	06/16/92	21:19	-	06/18/92	06:49	Forced	33.50	17,420.00
Descr: PUSH BUTTON BY OPERATOR. REHEAT TUBE LEAK.								
16.	07/09/92	00:47	-	07/11/92	00:23	Forced	47.60	24,752.00
Descr: OPERATOR INITIATED-BLOWN DIAPHRAM IN TURBINE. EXTRACTION STEAM LINE RE								
17.	07/11/92	00:25	-	07/11/92	03:22	Forced	2.95	1,534.00
Descr: LOSS OF IGNITION ENERGY-BOILER TRIP-41 MILL IGNITION ENERGY.								
18.	08/14/92	08:26	-	08/14/92	10:08	Forced	1.70	884.00
Descr: FURNACE PRESSURE HIGH PS708A. C&ET BLOWING FURNACE TAPS. LINE PRESSU								
19.	09/02/92	23:31	-	09/03/92	10:09	Forced	10.63	5,529.16
Descr: BOILER WATER PH 7.0. CONDENSER TUBE LEAK-DROVE BOILER CHEMISTRY OUT O								
20.	09/03/92	11:07	-	09/03/92	13:45	Forced	2.63	1,369.16
Descr: BOILER WATER PH 7.0. VERY LOW PHOSPHATE IN BOILER-ASSOCIATED WITH CON								
21.	09/18/92	00:00	-	09/19/92	06:24	Forced	30.40	15,808.00
Descr: OPERATOR OPENED GEN. BREAKER 10H354 ON REVERSE POWER BYPASS-BOILER SLA								
22.	10/03/92	11:16	-	10/03/92	17:32	Forced	6.27	3,258.32
Descr: #41 BUS TRIPPED AND STARTUP TRANSFORMER DID NOT WORK TAKING OFF ALL EQ								
23.	10/07/92	18:16	-	10/07/92	19:12	Forced	0.93	485.16
Descr: UNIT TRIPPED BY SWITCHYARD, RASA-LOST 345KV LINE. SWITCHYARD 500 LINE(
24.	10/18/92	17:02	-	10/18/92	18:39	Forced	1.62	840.32
Descr: STATOR OUTLES TEMP. HI DUE TO FAILURE OF TEMP. CONTROL VALVE.								
25.	10/28/92	23:00	-	10/29/92	19:53	Forced	20.88	10,859.16
Descr: BOILER TUBE LEAK-SUPERHEAT.								
26.	11/02/92	06:35	-	11/02/92	08:09	Forced	1.57	814.32
Descr: HIGH FURNACE PRESSURE DUE TO FCD MAIN BYPASS NOT OPERNING.								
27.	11/02/92	08:29	-	11/02/92	10:30	Forced	2.02	1,048.32
Descr: MANUAL TRIP BY OPERATOR. #1 MAIN STOP VALVE WOULD NOT OPEN. SERVO PL								

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #1								
9.	06/03/92	07:00	-	06/03/92	14:51	Forced	7.85	1,256.00
	Descr: UNIT OFF-PACKING LEAK W1 ECONOMIZER DRAIN							
10.	07/23/92	23:27	-	07/24/92	06:24	Maint.	6.95	1,112.00
	Descr: DEAERATOR DOOR LEAKING							
11.	09/10/92	11:23	-	09/11/92	21:47	Forced	34.40	5,504.00
	Descr: UNIT OFF - WATERWALL TUBE LEAK							
12.	10/16/92	21:42	-	11/16/92	12:57	Planned	736.25	117,800.00
	Descr: MAJOR BOILER OVERHAUL, EXCITER REPLACEMENT, HORIZ SH, ETC.							
13.	12/04/92	22:53	-	12/05/92	14:05	Forced	15.20	2,432.00
	Descr: UNIT OFF-GASKET LEAK ON DEAERATOR DOOR							
14.	12/08/92	17:26	-	12/09/92	00:14	Forced	6.80	1,088.00
	Descr: UNIT TRIP - EXCITER TRIPPED							
*** Unit Summary for Naughton #1 for the year 1992 =							1,106.40	177,026.40

Naughton #2

1.	01/27/92	21:27	-	01/31/92	14:15	Forced	88.80	18,648.00
	Descr: EROSION/WEAR - LEAK							
2.	05/08/92	23:12	-	06/10/92	02:49	Planned	771.62	162,039.36
	Descr: UNIT SCHEDULED OVERHAUL 4 WEEKS BOILER INTERNALS TURBINE VALVES, CIRC							
3.	06/10/92	06:30	-	06/10/92	16:38	Forced	10.13	2,127.93
	Descr: OVERSPEED TESTING - UNIT STARTUP							
4.	06/16/92	16:27	-	06/17/92	12:00	Forced	19.55	4,105.50
	Descr: UNIT OFF-CONDENSATE TUBE LEAK-1 TUBE PLUGGED; DA CONTROL VALVE PROBLEM							
5.	06/17/92	12:00	-	06/19/92	23:20	Forced	59.33	12,459.93
	Descr: UNIT OFF-GENERATOR GROUND RELAY PROBLEM							
*** Unit Summary for Naughton #2 for the year 1992 =							949.43	199,380.72

Naughton #3

1.	01/10/92	00:12	-	01/12/92	03:02	Forced	50.83	16,774.89
	Descr: WATERWALL TUBE LEAK(LEFT FRONT)							
2.	01/13/92	15:57	-	01/13/92	17:54	Forced	1.95	643.50
	Descr: CONDENSOR PROBLEMS							
3.	01/16/92	11:53	-	01/18/92	13:22	Forced	49.48	16,329.39
	Descr: WATER WALL TUBE LEAK							

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date	Time	-	Ending Date	Time	Outage Type	Hrs. Duration	MWH Lost
Naughton #3								
21.	12/05/92	18:59	-	12/07/92	12:54	Forced	41.92	13,832.28
Descr: UNIT OFF-WATERWALL TUBE LEAK								
22.	12/18/92	01:24	-	12/19/92	20:38	Forced	43.23	14,266.89
Descr: UNIT OFF-REHEAT TUBE LEAK								
*** Unit Summary for Naughton #3 for the year 1992 =							850.25	280,580.19

Wyodak

1.	02/09/92	10:59	-	02/09/92	19:00	Forced	8.02	2,565.12
Descr: TRIP FROM BLACK HILLS SPEARFISH LINE, RELAYING DID NOT CLEAR LINE								
2.	02/09/92	19:00	-	02/10/92	09:00	Forced	14.00	4,480.00
Descr: OPERATOR OPENED WRONG VALVE WHICH FLOODED DA AND SHORTED OUT MCC'S								
3.	02/10/92	09:00	-	02/10/92	15:00	Forced	6.00	1,920.00
Descr: START-UP DELAYED DUE TO PROBLEMS WITH IGNITORS								
4.	02/10/92	15:00	-	02/10/92	17:00	Forced	2.00	640.00
Descr: DELAY TO START-UP BECAUSE OF DRUM LEVEL, PROBLEMS WITH DRUM SWELL								
5.	02/10/92	17:00	-	02/10/92	20:44	Forced	3.73	1,194.56
Descr: DELAY TO START-UP BECAUSE OF REPAIRS TO BURNER								
6.	05/15/92	23:31	-	05/17/92	04:30	Maint.	28.98	9,274.56
Descr: PLUGGED REHEATER DUE TO POOR QUALITY COAL AND OVERFIRING BOILER								
7.	05/17/92	04:30	-	05/17/92	07:32	Maint. Ext.	3.03	970.56
Descr: A3, B3, C-GROUP, E-GROUP LIGHTERS HAD PLUGGED TIPS AND AIR PRESSURE								
8.	06/19/92	23:41	-	06/20/92	19:42	Maint.	20.02	6,405.12
Descr: WATER WALL TUBE LEAK - FRONT VESTIBULE								
9.	06/20/92	19:42	-	06/20/92	22:42	Forced	3.00	960.00
Descr: PLUGGED IGNITORS AND OTHER PROBLEMS WITH IGNITORS								
10.	06/23/92	00:16	-	06/24/92	01:07	Forced	24.85	7,952.00
Descr: WATER WALL TUBE LEAK - THROAT								
11.	06/24/92	01:07	-	06/24/92	01:37	Forced	0.50	160.00
Descr: PROBLEMS WITH BFP RECIRC VALVES								
12.	06/24/92	01:37	-	06/24/92	04:07	Forced	2.50	800.00
Descr: PLUGGED IGNITERS AND OTHER PROBLEMS WITH IGNITERS								
13.	09/04/92	21:27	-	09/05/92	03:17	Forced	5.83	1,866.56
Descr: UNIT TRIPPED DURING TURBINE OVERSPEED TEST DUE TO TIMING RESET PROBLEM								

1992 Power Plant Outages

Listed by Unit in Chronological Order

NO.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Blundell						
5.	04/08/92 06:05	-	04/08/92 18:34	Forced	12.48	262.14
	Descr: CONDENSATE POT REPAIRS/VENT STACK VALVE MAIN STEAM LINE					
6.	04/09/92 01:25	-	04/09/92 04:20	Forced	2.92	61.24
	Descr: UNIT TRIPPED; STEAM SEALS TURBINE EXHAUST LOW VACUUM					
7.	04/22/92 16:05	-	04/22/92 19:10	Forced	3.08	64.74
	Descr: UNIT RUNBACK; #44 BREAKER AT CAMERON TRIPPED					
8.	04/29/92 13:10	-	04/29/92 13:40	Forced	0.50	10.50
	Descr: RUNBACK; #44 BREAKER AT CAMERON SUBSTATION OPENED					
9.	05/22/92 10:08	-	05/22/92 10:26	Forced	0.30	6.30
	Descr: OCB21 TRIPPED; MINERAL MT./COVE FORT 46 KV LINE TRIPPED					
10.	05/24/92 13:52	-	05/24/92 14:10	Forced	0.30	6.30
	Descr: CAMERON SUB OCB44 BREAKER OPENED, CAUSING OCB21 TO TRIP/UNIT RUNBACK					
11.	06/12/92 15:50	-	06/12/92 16:24	Forced	0.57	11.89
	Descr: UNIT RUNBACK; CAMERON LINE TRIP					
12.	08/02/92 13:38	-	08/02/92 14:32	Forced	0.90	18.90
	Descr: CO1B DISCHARGE CLOSED AND UNIT WAS LOST					
13.	08/29/92 15:34	-	08/29/92 17:10	Forced	1.60	33.60
	Descr: LOST PLANT INSTRUMENT AIR					
14.	08/30/92 21:32	-	08/31/92 00:04	Forced	2.53	53.19
	Descr: OCB-21 TRIPPED AND UNIT TRIPPED. LIGHTNING AND VOLTZ/HZ RELAY					
15.	09/06/92 15:29	-	10/05/92 13:50	Planned	694.35	14,581.35
	Descr: PLANT OVERHAUL					
16.	10/07/92 11:50	-	10/07/92 12:27	Forced	0.62	12.94
	Descr: UNIT RUNBACK; LINE TROUBLE AT SIGURD ON 138KV LINE					
17.	11/22/92 07:02	-	11/22/92 07:21	Forced	0.32	6.64
	Descr: UNIT TRIPPED DUE TO FAULTY #1 EHC PUMP WHILE TESTING STOP VALVE					
18.	12/12/92 03:53	-	12/12/92 04:43	Forced	0.83	17.49
	Descr: OCB21 TRIPPED; LINE FAULT IN MINERSVILLE					
19.	12/12/92 21:19	-	12/12/92 21:27	Forced	0.13	2.79
	Descr: OCB21 CIRCUIT BREAKER TRIPPED; LINE FAULT IN SIGURD					
*** Unit Summary for Blundell for the year 1992 =					736.37	15,463.57

Sch. 36 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	Zero Interest Program						
2	Initiated - 1978	\$5,000	\$4,198	19.10%	0.00	7	0.00
3	Projected Life - Indefinite						
4	Low Income Program						
5	Initiated - 1987	\$52,500	\$47,541	10.43%	0.00	33	0.00
6	Projected Life - Indefinite						
7	Efficient Heat Pump						
8	Initiated - 1986	\$10,000	\$9,400	6.38%	0.01	95	0.01
9	Projected Life - Indefinite						
10	Efficient Water Heaters						
11	Initiated - 1987	\$7,000	\$6,155	13.73%	0.00	40	0.00
12	Projected Life - Indefinite						
13	Super Good Cents						
14	Initiated - 1988	\$200,400	\$142,092	41.04%	0.04	303	0.00
15	Projected Life - Indefinite						
16	Manufactured Acquisition Program						
17	Initiated - 1991	\$205,743	\$62,400	229.72%	0.04	360	(0.02)
18	Projected Life - Indefinite						
19	Energy FinAnswer						
20	Initiated - 1991	\$55,000	\$1,560	3425.64%	0.01	119	0 (0.01)
21	Projected Life - Indefinite						
22	Energy FinAnswer 12,000						
23	Initiated - 1992	\$79,294	\$12,704	524.17%	0.02	196	0 (0.02)
24	Projected Life - Indefinite						
25							
26							
27							
28							
29							
30							
31							
32							
33	TOTAL	\$614,937	\$286,050	114.98%	0.12	1,153	0.08 (0.04)
						740	(413)

Program	"Participant" Description	Conservation "Unit" Description	1992 Participants	1992 Units Acquired/Processed
Zero Interest Program	Any Single Family home owner with permanently connected electric heat. Must meet minimum credit approval.	Homes Weatherized	8	8
Low Income Program	Any residence w/electric heat as the primary heat source. Must meet income requirement: 125% of Federal poverty level.	Homes Weatherized Water Heater refurbish/replace	38 88	38 88
Efficient Heat Pumps	Small Commercial or Residential customers with 1.5 - 7.5 ton Heat Pump installed by an H-Pro dealer. Must have HSPF standard ≥ 7.0	Heat Pump: Air to Air or Ground Source	74	74
Efficient Water Heaters	Any Single Family home owner may sign up for Hassle Free program which pays for replacement of their electric water heater with a more efficient unit if it fails.	Water Heaters Replaced	122	122
Super Good Cents	Any builder or owner of a New residential, electrically heated home in Pacific Power's Montana service territory.	New Homes	57	57
Manufactured Acquisition Program	Manufacturers of New electrically heated manufactured homes.	New Manufactured Homes	14	14
Energy FinAnswer	Owners or developers of new commercial buildings or new additions over 12,000 square feet.	Square footage of treated space	0	0
Energy FinAnswer 12,000	Owners or developers of new commercial buildings or new additions under 12,000 square feet.	Square footage of treated space	0	0